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NUREG-0896
Supplement No. 5

# Safety Evaluation Report
## related to the operation of Seabrook Station, Units 1 and 2

Docket Nos. 50-443 and 50-444

Public Service Company of New Hampshire, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

July 1986

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**Office of Nuclear Reactor Regulation**

July 1986

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# ABSTRACT

This report is Supplement No. 5 to the Safety Evaluation Report (NUREG-0896, March 1983) for the application filed by the Public Service Company of New Hampshire, et al., for licenses to operate Seabrook Station, Units 1 and 2 Docket Nos. STN 50-443 and STN 50-444). It has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission and provides recent information on open items identified in the SER. The facility is located in Seabrook, New Hampshire. Subject to favorable resolution of the items discussed in this report, the staff concludes that the facility can be operated by the applicant without endangering the health and safety of the public.

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# 1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

## 1.1 Introduction

On March 7, 1983, the Nuclear Regulatory Commission staff (NRC or staff) issued a Safety Evaluation Report (SER), NUREG-0896, on the application of Public Service Company of New Hampshire (PSNH, hereinafter referred to as the applicant) for licenses to operate Seabrook Station, Units 1 and 2. In April 1983, the NRC issued the first supplement to the SER (SSER 1), in June 1983 the second supplement (SSER 2) was issued, in July 1985 the third supplement (SSER 3) was issued, and in May 1986 the fourth supplement (SSER 4) was issued to that document. This fifth supplement (SSER 5) provides information to update the status of the NRC review.

Each of the sections and appendices of this supplement is designated the same as the related portion of the SER. The contents of this document are supplementary to the initial SER, SSER 1, SSER 2, SSER 3, and SSER 4, and not in lieu of those documents unless otherwise noted. Appendix A is a continuation of the chronology of this safety review. Appendix B lists reference materials cited in this document.* Appendix D lists acronyms and initialisms used in this supplement. Appendix F gives the principal staff contributors. Appendix H is a continuation of errata to the SER and its supplements. Appendix K evaluates the applicant's request for an exemption from a portion of General Design Criterion (GDC) 4 of Appendix A to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR 50). Appendix L is a Technical Evaluation Report discussing the applicant's compliance with Regulatory Guide (RG) 1.97. Appendix M evaluates the applicant's preservice inspection relief request. Appendix N is a Technical Evaluation Report (TER) that reviews the load-handling policy and procedures at Seabrook. Appendix O is a TER that deals with SER Confirmatory Issue No. 25. Appendix P is an analysis of the cable and raceway separation criteria for Seabrook. Appendix Q is a TER that evaluates containment purge and vent valve operability at Seabrook. Appendices C, E, G, I, and J have not been changed by this supplement.

The NRC Project Manager for the Seabrook operating license (OL) review is Mr. Victor Nerses. He may be reached by telephone at 301 492-8535 or by mail at the following address:

Mr. Victor Nerses, Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

## 1.7 Outstanding Issues

Section 1.7 of the SER noted that certain outstanding issues in the staff's review had not been resolved by the time the report was issued. This supplement

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closes nine items. These items and the sections of this supplement that present results of the staff's evaluation are given below. Outstanding issues listed below that are discussed in sections followed by an asterisk become license conditions. Outstanding issues listed below that are discussed in sections followed by a double asterisk become confirmatory items.

(2) Emergency preparedness (2.3.3,** 13.3*)

(4) Preservice and inservice inspection and testing programs (2.5.5.3, 3.9.6,** 5.2.4,* 6.6.3*)

(6) Environmental qualification of equipment (3.11**)

(8) TMI Action Plan items (4.4.5.4,** 6.2.8, 9.3.4.2, 13.3,* 14,* 15.9.9)

(10) Level measurement error (7.3.2.8)

(11) Instrumentation and control for safe shutdown (7.4.2.1,** 7.4.2.4)

(12) Radiation data management system (7.5.2.2*)

(14) Solid radwaste management system (11.4)

(16) Shift Technical Advisor, TMI Action Plan Item I.A.1.1 (13.1.2.2, 13.2.2.1)

As of this supplement, the remaining outstanding issues and the related SER sections are

(6) Stress/dynamic qualification of equipment (3.10)

(20) Fire protection (9.5.1.9)

## 1.8 Confirmatory Issues

Section 1.8 of the SER noted that there are some items that have been resolved essentially to the staff's satisfaction but for which certain confirmatory information has not yet been provided by the applicant. This supplement closes 11 of the confirmatory items. These items and the sections of this supplement that present results of the staff's evaluation are given below. The confirmatory issue listed below that is discussed in the section followed by an asterisk becomes a license condition. The confirmatory issue listed below that is discussed in the section followed by a double asterisk becomes an outstanding issue.

(1) Underground transmission line easement (2.1.2)

(12) Analysis of the containment purge and vent system (6.2.4, 6.2.8)

(13) Containment subcompartment analysis (6.2.1.2)

(14) Formal documentation of previously provided information related to several instrumentation and control systems (7.2.2, 7.4.2.5, 7.6.7.6)

(16) Main steam atmospheric relief valves (7.4.2.2)

(17) Pressurizer auxiliary spray (7.4.2.5)

(31) Diesel generator exhaust inspection and protection (9.5.8)

(37) Health physics organization (12.5.1)

(40) Inadvertent boron dilution (15.4.6)

(41) Systems outside containment containing radioactive material, TMI Action Plan Item III.D.1.1 (15.9.15*)

(42) Stress/dynamic qualification of equipment (3.10**)

As of this supplement the remaining and additional confirmatory items are given below. The staff has decided that the confirmatory issues listed below that are discussed in sections followed by an asterisk may be resolved after core load.

(6) Loose parts monitoring system (4.4.5.3*)
(24) Non-safety loads powered from the Class 1E ac system (8.3.1.4)
(33) Sampling capability for vacuum pumps during startup (10.4.2)
(45) Steam generator tube rupture (15.6.3*)
(46) Electrical power systems, general (8.1)
(47) Environmental qualification of equipment (3.11)
(48) Instrumentation and control for safe shutdown (7.4.2.1)
(49) Cable tray supports (3.7.3*)
(50) Turbine system maintenance program (3.5.1.3*)
(51) Inadequate core cooling, TMI Action Plan Item II.F.2 (4.4.5.4*)
(52) Postaccident monitoring (7.5.2.4*)
(53) Inservice testing of pumps and valves (3.9.6*)
(54) Tests, operational procedures, and support systems (5.4.7.5*)

For a number of confirmatory issues, the remaining action involves verification by the NRC staff that the applicant has implemented its commitments with regard to such items as equipment installation or modification, alarms or setpoints, and plant procedures or testing. The following confirmatory issues are included in this verification category:

(43) PVORT equipment-specific issues and generic issues (3.10.2.3)
(44) Administrative procedures (13.5.1)
(45) Emergency preparedness (2.3.3)

Verification of items (43), (44), and (45) will be accomplished as part of the ongoing inspection program for Seabrook conducted by NRC Region I inspection staff. The Region I inspection staff will ensure that these items are completed and will report on the status of their completion.

## 1.9 License Condition Items

In Section 1.9 of the SER, the staff noted several issues for which a license condition may be desirable to ensure that staff requirements are met during plant operation if those requirements have not been met before the operating license is issued. The license condition may be in the form of a condition in the body of the operating license, or a limiting condition for operation in the Technical Specifications appended to the license.

This supplement closes seven license condition items. These items and the sections of this supplement that present results of the staff's evaluation are given below. License condition items listed below that are discussed in sections followed by an asterisk become confirmatory items. The license condition item listed below that is discussed in the section followed by a double asterisk becomes an outstanding issue.

(1) Turbine system maintenance program (3.5.1.3*)

(3) Detection of inadequate core cooling, TMI Action Plan Item II.F.2 (4.4.5.4,* 4.4.8)

(5) Natural circulation tests (5.4.7.5)

(8) Compliance with NUREG-0612 (control of heavy loads) (9.1.5)

(9) Postaccident sampling, TMI Action Plan Item II.B.3 (9.3.4.2)

(10) Secondary water chemistry monitoring and control (10.3.5)

(12) Shift Technical Advisor, TMI Action Plan Item I.A.1.1 (13.1.2.2, 13.2.2.1)

(14) Solid radwaste management system (11.4**)

As of this supplement the remaining license condition items are

(4) Inservice inspection program (5.2.4, 6.6.3)

(13) Emergency preparedness (13.3)

(16) Implementation and maintenance of the physical security plan (13.6)

(17) Training during low-power testing, TMI Action Plan Item I.G.1 (14)

(21) Control room design review, TMI Action Plan Item I.D.2 (18)

(22) Radiation data management system (7.5.2.2)

(23) Fire protection (9.5.1.9)

(24) Systems outside containment containing radioactive material, TMI Action Plan Item III.D.1.1 (15.9.15)

## 1.10 Nuclear Waste Policy Act of 1982

Section 302(b) of the Nuclear Waste Policy Act of 1982 states that NRC shall not issue or renew a license for a nuclear power reactor unless the utility has signed a contract with the Department of Energy (DOE) for disposal services, or the Secretary of Energy affirms in writing that a utility is actively and in good faith negotiating with DOE for a contract. The applicant has provided the staff with a copy of its contract with DOE (entered into on June 27, 1986, U.S. DOE Contract No. DE-CR01-86RW00111) regarding the disposal of spent nuclear fuel and/or high level radioactive waste. The requirement for the applicant's execution of a contract with DOE as specified in Section 302(b) of the Nuclear Waste Policy Act of 1982 has been met.

# 2 SITE CHARACTERISTICS

## 2.1 Geography and Demography

### 2.1.2 Exclusion Area Control

In the SER the staff found, pending the confirmation of a formal agreement with the Exeter and Hampton Electric Company, that the applicant has the authority to determine all activities within the exclusion area, as required by 10 CFR 100. Confirmation of such an agreement was left as Confirmatory Item No. 1, "Underground Transmission Line Easement." The staff has received and reviewed a copy of an agreement between Exeter and Hampton Electric Company and the applicant, dated May 29, 1986. The agreement gives the applicant the authority to control the activities of the Exeter and Hampton Electric Company within the exclusion area in the event of a nuclear incident. Rather than the underground transmission line easement routed to the south of the plant site shown in the SER (Figure 2.3), the transmission line is now above ground and goes around the plant site to the north as shown in Figure 2.1 of this supplement. Confirmatory Item No. 1 is resolved.

## 2.3 Meteorology

### 2.3.3 Onsite Meteorological Measurements Program

The SER identified open items related to the description of the operational meteorological measurements program and the use of the meteorological information for emergency response purposes. By letter dated May 9, 1986, the applicant provided revisions to Final Safety Analysis Report (FSAR) Section 2.3.3 and Emergency Plan Section 6.2.3 that describe the operational meteorological measurements program. The Emergency Plan Implementation Appraisal (EPIA), conducted in December 1985 and March 1986, addressed the use of meteorological information for emergency response purposes (see Inspection Reports 50-443/85-32 and 50-443/86-18).

The same tower as that used to provide data for the second phase (after April 1979) of the preoperational program with instruments at the same elevations previously described in Section 2.3.3 of the SER will be used for the operational meteorological measurements program. The applicant has upgraded the data collection system and provided instrumentation specifications for the new digital and analog recording systems. The system accuracies determined by the applicant for the recording systems satisfy the specifications in RG 1.23 for primary meteorological parameters (i.e., wind speed, wind direction, and vertical temperature difference) with the exception of the accuracy of the wind direction using the analog recording system. Because the analog system is used as a backup to the digital system and because the deviation from the recommended accuracy is small (±7.5° compared with ±5°), deviation from RG 1.23 is not considered significant. The operational meteorological measurements program will continue to be monitored through routine NRC inspection activities,

b

and any problems will be followed through the inspection process. The description of the operational meteorological measurements is adequate to close the outstanding issue.

During the two-phase EPIA conducted by Region I staff in December 1985 and March 1986, the appropriateness and quality of meteorological data available for use in emergency response were reviewed as part of the operational meteorological measurements program. Inspection Report 50-443/85-32 identified a number of "improvement items" related to meteorological data. (The "improvement item" classification means that compliance with requirements is marginal and that improvements should be made.) In a followup Region I inspection, documented in Inspection Report 50-443/86-18, it was noted that while the improvements have not yet been made, a description of anticipated applicant actions was provided. Thus, these items are being appropriately addressed by inspection actions and will be completed by fuel load. The completion of these items will be reported by Region I staff. Therefore, with these actions the staff concludes that the outstanding issue related to the use of meteorological information for emergency response is closed pending confirmation from Region I.

## 2.5 Geology and Seismology

### 2.5.5 Stability of Slopes

### 2.5.5.1 Slope Characteristics

In the SER, the staff stated that two designs would be used in constructing stone revetments to protect portions of the perimeter of the plant that could be exposed to wave action during the peak probable maximum hurricane (PMH) surge. After the SER was issued, the applicant revised the stone revetment designs and proposed three designs instead of the original two. (See Figure 2.2.) These revisions were due to changes in the site topography that occurred during construction.

The original design for revetment "B" had been based on a slope that extended to the original land elevation. During construction, however, the land area east of revetment "B" was graded to an elevation of about 13 ft above mean sea level (msl). This higher ground provides significant flood protection and results in a reduction in the height of the design waves that could impact on revetment "B" during a PMH. As a result, the applicant reduced the size and weight of the stone required for design of revetment "B."

In the SER, the staff stated that design "A" would be used for the south and southeast stone revetments. This has been revised: Design "A" will now be used for the south perimeter revetment only. A new design, "C," will be used for the southeast portion of the revetment as shown on Figure 2.2. This new design was also due to changes in site topography that resulted in a reduction in the calculated design wave height along revetment "C." The size and weight of the stones required for revetment "C" were reduced consistent with the reduced wave height.

In Section 2.5.5.1 of the SER, the staff stated that revetment design "A" would consist of a 6-ft layer of armor stones weighing between 1.5 to 3 tons each, overlying a 3-ft layer of stones weighing 300 to 600 lb each, overlying

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a 1.2-ft layer of stones weighing 15 to 30 lb each. Design "B" consisted of a 3.6-ft layer of armor stones weighing between 700 to 1200 lb each, overlying a 1.6-ft layer of stones weighing between 70 to 120 lb each. As discussed above, design "B" has been revised, and design "C" has replaced a portion of revetment design "A." The new revetment stone sizes are shown in Table 2.1 of this supplement.

On the basis of its analysis of the changed site conditions, the redesign of revetment "B," and the new design of revetment "C," the staff concluded in Section 2.4.10 of Supplement No. 3 to the SER that these shore protection features would protect the plant against the design-basis flood. The staff thus concluded in SER Supplement No. 3 that the plant meets the guidelines of RG 1.102 and the requirement of GDC 2 of Appendix A to 10 CFR 50 with respect to flooding.

In Section 2.5.5.1 of the SER, the staff also stated that the applicant had committed to remove all topsoil and to prepare the supporting surface before the revetment stone was put in place. The supporting surface was to be natural bedrock, in-place dense glacial till, or offsite borrow compacted to 90% modified Proctor (American Society for Testing and Materials Standard ASTM D-1557) or greater. A polypropylene filter cloth was to be placed between the revetment stone and supporting slope and toe materials to reduce the potential for erosion and scour.

To show that this commitment has been met, the applicant, in a letter dated May 7, 1986, from J. DeVincentis, PSNH, to V. S. Noonan, NRC, provided pertinent portions of two of the specifications, 9763-8-2 and 9763-8-4, that had been used in constructing the revetments.

To comply with the commitment to remove all topsoil and to prepare the revetment supporting surface before placement of the revetment stone, the specifications required removal of soil to at least 2 ft 0 in. below the required finished elevation. Earth removed below the required elevation was to be replaced with compacted random fill to the correct elevation. The compaction criterion specified was 90% of maximum density as determined by the modified Proctor compaction test (ASTM D-1557).

The specifications also addressed the commitment to install a polypropylene filter cloth to prevent erosion. Surfaces on which the filter cloth was required were to be prepared to a smooth condition free of obstruction, depressions, and debris. The specifications also described how the filter cloth was to be shipped and stored and how edges were to be selvaged to prevent unraveling.

In addition to reviewing Specifications 9763-8-2 and 9763-8-4, the staff reviewed a letter that had been submitted to the staff on May 31, 1984. Drawings attached to this letter showed typical sections for placement of the revetment on bedrock and soil. The drawings also indicated how and where the polypropylene filter cloth was to be placed.

On the basis of its review of the May 7, 1986, and May 31, 1984, letters from the applicant, the staff concludes that the commitment by the applicant to use specified procedures in constructing the revetments as discussed in Section 2.5.5.1 of the SER have been met. The staff thus considers this issue resolved.

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### 2.5.5.3 Conclusion

In Section 2.5.5.3 of the SER, the staff stated that the applicant had committed to develop an appropriate inservice inspection and surveillance program for the revetments and to include the revetments as items to be inspected under RG 1.127, "Inspection of Water Control Structures Associated With Nuclear Power Plants." By letter dated March 18, 1986, from J. DeVincentis, PSNH, to V. S. Noonan, NRC, the applicant provided details of the revetment surveillance program. This program will monitor the performance of the reinforced concrete seawall, the sheet pile retaining wall, and the rock revetment structures.

The staff has reviewed the applicant's proposed surveillance program and concludes that it meets the recommendations of RG 1.127. Thus, the portion of SER Outstanding Issue No. 4 that addresses SER Section 2.5.5.3 is resolved.

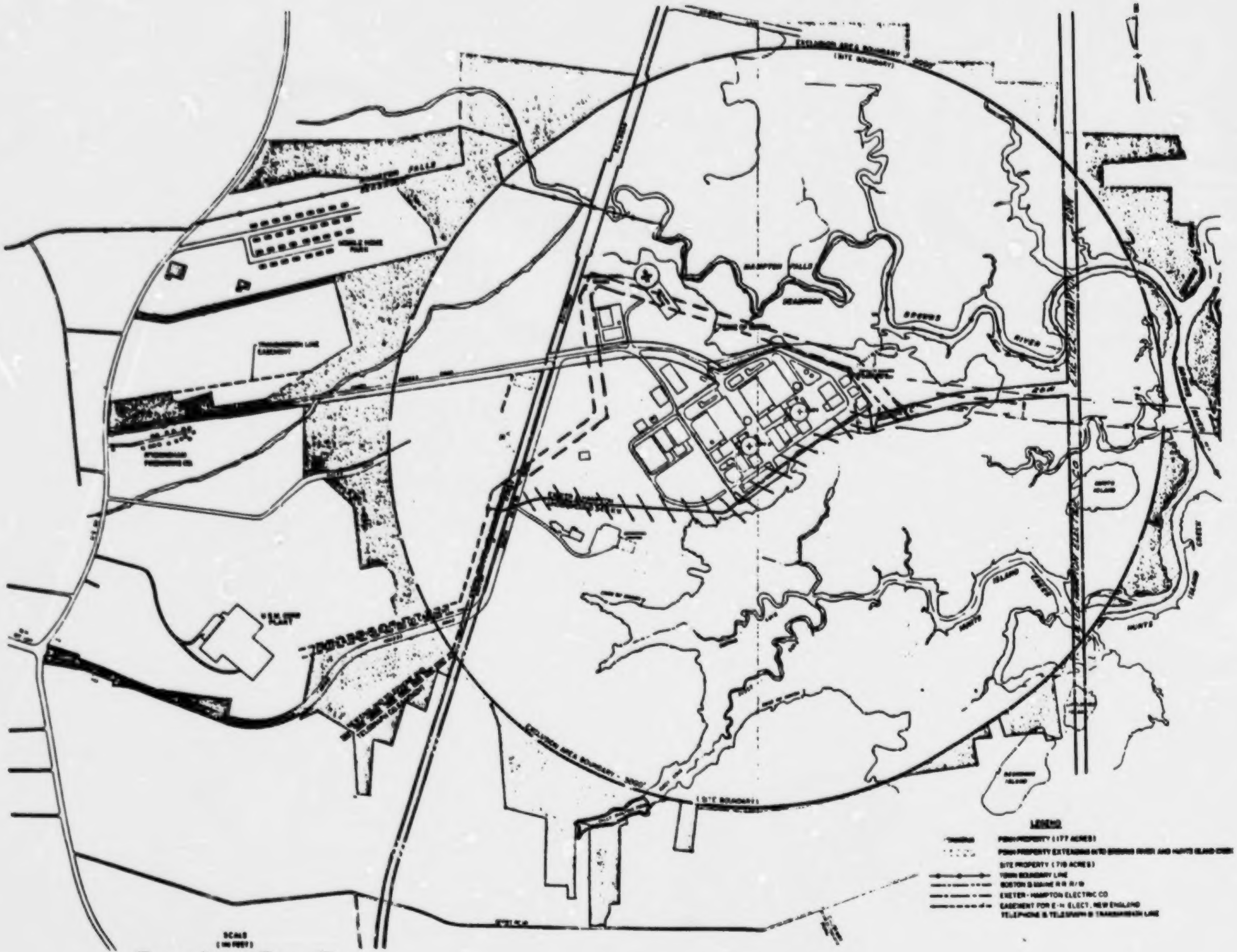
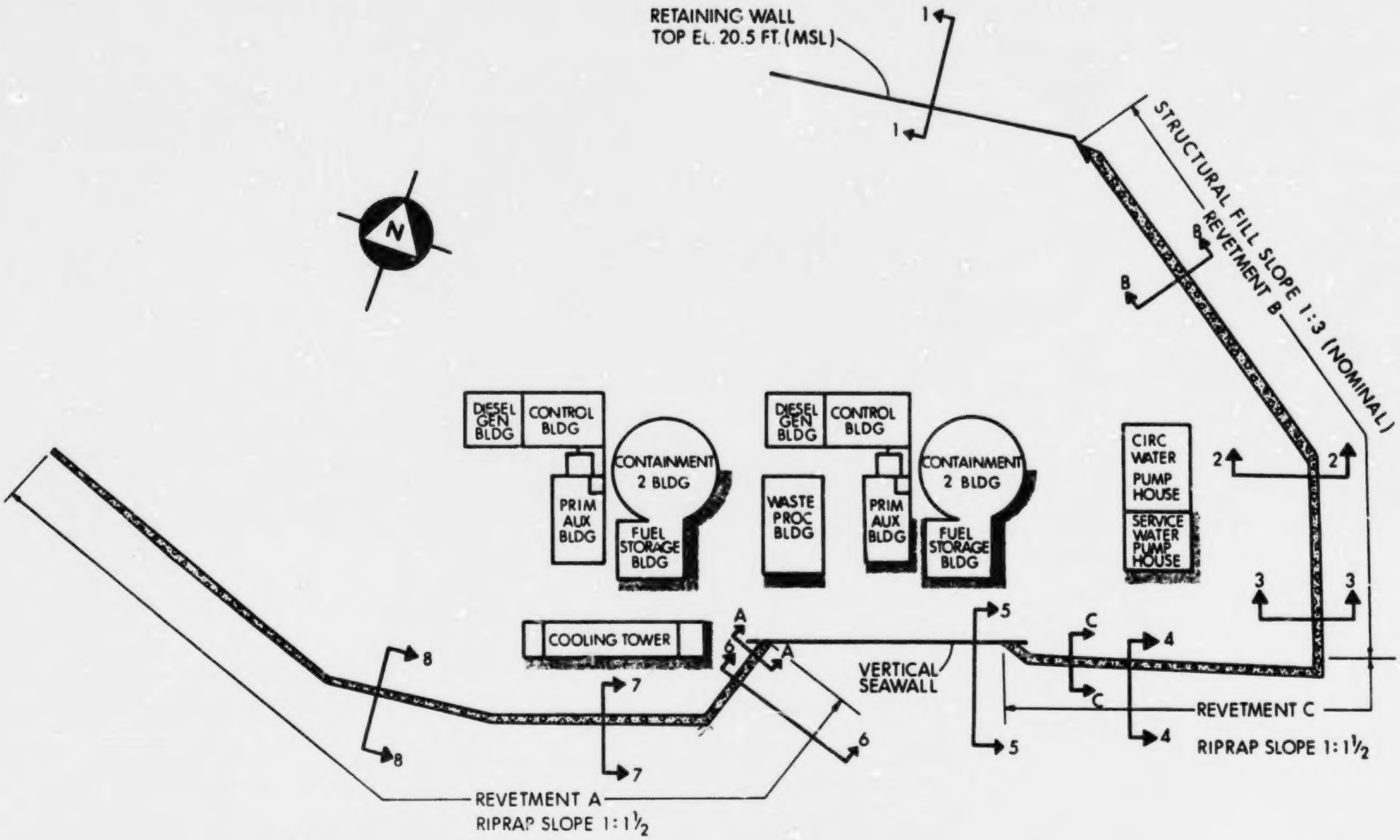

EXCLUSION AREA BOUNDARY
(SITE BOUNDARY)
HAMPTON FALLS
SEABROOK
BROWNS RIVER
SCALE
(IN FEET)
LEGEND
PSNH PROPERTY (177 ACRES)
PSNH PROPERTY EXTENDING INTO BROWNS RIVER AND HUNTS ISLAND CREEK
SITE PROPERTY (719 ACRES)
TOWN BOUNDARY LINE
BOSTON & MAINE R R R/W
EXETER - HAMPTON ELECTRIC CO
EASEMENT FOR E-H ELECT, NEW ENGLAND
TELEPHONE & TELEGRAPH & TRANSMISSION LINE

Figure 2.1 Seabrook site boundaries
Source: FSAR Figure 2.1-4A, Amendment 45, June 1982


RETAINING WALL
TOP EL. 20.5 FT. (MSL)
1
1
N
STRUCTURAL FILL SLOPE 1:3 (NOMINAL)
REVETMENT B
B
B
DIESEL GEN BLDG
CONTROL BLDG
CONTAINMENT 2 BLDG
PRIM AUX BLDG
FUEL STORAGE BLDG
DIESEL GEN BLDG
CONTROL BLDG
WASTE PROC BLDG
CONTAINMENT 2 BLDG
PRIM AUX BLDG
FUEL STORAGE BLDG
CIRC WATER PUMP HOUSE
SERVICE WATER PUMP HOUSE
2
2
3
3
COOLING TOWER
A
A
6
6
5
5
C
C
4
4
VERTICAL SEAWALL
8
8
7
7
REVETMENT C
RIPRAP SLOPE 1: 1½
REVETMENT A
RIPRAP SLOPE 1: 1½

NOTE: ▨ INDICATES WALLS OF STRUCTURES SUBJECT TO WAVE RUNUP

Figure 2.2 Wave protection--revetments and seawall
Source: FSAR Figure 2.4-20, Amendment 53, August 1984

//

Table 2.1  Revetment stone sizes

| Class | Weight | Thickness (ft) |
|---|---|---|
| Revetment A | | |
| Armor stone | 1.5-3.0 tons | 6 |
| A layer | 300-600 lb | 3 |
| B layer | 15-30 lb | 1.2 |
| Revetment B | | |
| B layer | 15-30 lb | 1-2.5 |
| Revetment C | | |
| Armor stone | 0.5-1.0 ton | 4.8 |
| A layer | 50-200 lb | 2.2 |

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# 3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

## 3.5 Missile Protection

### 3.5.1 Missile Selection and Description

### 3.5.1.3 Turbine Missiles

By letter dated June 9, 1986, the applicant committed to adopt a turbine maintenance program recommended by the maufacturer based on turbine missile generation. On the basis of this commitment, the applicant will submit for NRC approval, within 3 years of obtaining an operating license, a turbine system maintenance program. The contents of this program will be based on the manufacturer's calculations of missile generation probabilities.

If the applicant is unable to provide the turbine system maintenance program as described above, the staff will require the applicant to volumetrically inspect all low-pressure turbine rotors at the second refueling outage, as stated in Section 3.5.1.3 of the SER, and every other (alternate) refueling outage thereafter until some other maintenance program is approved by the staff.

## 3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

### 3.6.2 Determination of Rupture Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

On November 22, 1985, the staff approved the applicant's request for exemption from a portion of GDC 4 of Appendix A to 10 CFR 50 regarding the need to analyze large primary loop pipe ruptures as a structural design basis for Seabrook Units 1 and 2. Appendix K contains the exemption, the staff's safety evaluation, and the related "Environmental Assessment and Finding of No Significant Impact."

## 3.7 Seismic Design

### 3.7.3 Seismic Subsystem Analysis

The design criteria for Seabrook cable tray supports as described in the FSAR were previously reviewed and accepted by the staff. The criteria are generally based on conservative modeling assumptions, analytical methods, and design codes stipulated in Sections 3.7 and 3.8 of the Standard Review Plan (SRP) (NUREG-0800). The applicant's implementation of these conservative design criteria resulted in the installation of a considerable amount of lateral and axial bracing to resist the computed seismic loads. This need for providing heavy bracing led the applicant to reevaluate the cable tray support design approaches. The applicant also developed a dynamic test program involving shake table tests of representative Seabrook-specific cable tray supports.

During the December 3, 1985, meeting at Bethesda, Maryland, the applicant proposed a dynamic testing program for cable tray supports as an alternate method to the staff-approved design procedures and criteria for cable tray supports as described in the FSAR.

By letter of December 20, 1985, the applicant submitted a report, "Cable Tray Support Qualification Program, December 1985," and requested staff approval of the dynamic tests program. Subsequent technical meetings between the applicant, its consultants, and the NRC staff were held in Bethesda on January 14, 1986, and at the Seabrook site on March 19, 1986. The applicant provided further information on Seabrook cable tray supports in a letter dated April 3, 1986, and in the revised report, "Cable Tray Support Qualification Program," dated March 31, 1986 transmitted by letter dated April 3, 1986. Responses to the staff's requests for information were also provided on May 7, 1986.

The staff has reviewed the summaries of the meetings mentioned above and the applicant's letters and reports (also mentioned above). The paragraphs that follow discuss the staff's review findings and conclusions.

### Description of Cable Tray Qualification Program

The qualification program is based on plant-specific cable tray support tests of the existing Seabrook cable tray support configurations to meet seismic qualification requirements in their present state of completion. It includes full-scale dynamic testing on representative support and tray configurations at high levels of seismic input. The test data have been used to develop an analytical approach based on actual predictable system behavior. The stated objective is to produce and implement a methodology that will optimize Seabrook's use of available resources and meet appropriate acceptance criteria and design margins.

Of 11 seismic Category I buildings, 7 still require final documentation of their qualification of cable tray supports. The remaining four buildings have been completed in terms of design, installation, and final documentation of cable tray supports, based on the original staff-approved design criteria. A review of all supports located inside the seven seismic Category I buildings is planned by the applicant using as-constructed drawings and walkdown results. Individual support qualification will be accomplished by testing, envelope analysis, or support-unique analysis. Support qualification by testing will be used when the support geometry, hardware material, mass and seismic environment, etc., are bounded by a specific full-scale test case. Supports not qualified exclusively by testing will be qualified by analysis. Envelope analysis will be used as much as practical to optimize the analytical program and provide additional design margin. When the envelope approach, however, is not appropriate, supports will be analyzed on an individual basis.

The qualification test data base was developed by shake table testing of three representative support configurations which are predominant throughout the seven seismic Category I buildings. The system behavior of each of the configurations was obtained by testing full-scale systems. The qualification of support configurations that are not geometrically bounded by the three tested configurations will be supplemented by analysis. Analytical refinements, derived as a result of the test program, will be incorporated by the applicant where possible to facilitate the implementation of the analysis program. An envelope analysis approach will be used for supports that can be grouped by

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configuration type. Representative envelope models are developed utilizing conservative values of cable tray parameters, thereby facilitating their use to qualify multiple applications. Any support configuration that is not qualified by either testing or the envelope analysis approach will require a unique support evaluation. This evaluation can range in scope from a complete individual support analysis (if the configuration differs significantly from any previously qualified configuration) to an evaluation that addresses any minor difference between the support and a previously qualified configuration.

The analysis of cable tray support configurations will be evaluated against detailed acceptance criteria. The acceptance criteria consist of the existing criteria included in the FSAR and, as appropriate, some enhancements of the criteria to reflect findings from the Seabrook-specific tests. The staff-approved acceptance criteria were used, unless the test program results dictated a necessary change. Among the key acceptance criteria considered were structural performance criteria (e.g., allowable stresses and strains, capacities of connections, and tray holddown devices as supplemented by test data), system displacement, and interaction criteria.

The final report entitled "Cable Tray Support Qualification Program" provides a more detailed description of the qualification program, qualification methods, qualification criteria, and evaluation procedures. Included as an appendix to the report is a comparison of cable trays at the Seabrook Station with the seismic experience data base of cable trays compiled for other plants.

### Evaluation Finding

#### (1) Qualification by Dynamic Test Program

Three test configurations believed to be the most representative of site conditions are used. They are (a) the trapeze support, (b) the typical floor-to-ceiling support, and (c) the change-in-direction support. Each test configuration is subjected to the following three different load sequences and input levels:

(a) safe shutdown earthquake (SSE) test--one SSE test response spectrum (TRS)

(b) fatigue test--five operating basis earthquake (OBE) TRS followed by one SSE TRS

(c) fragility test--scaled up to 1.2 to 1.5 times the SSE TRS

ANCO Engineers of Culver City, California, performed the dynamic testing of Seabrook cable tray supports for Bechtel Power Corporation. Variables for investigation include types and manufacturers of trays, type and size of tray supports, location of tray splices, number of tray tiers, configuration of support systems, type and spacing of transverse and longitudinal bracings, weight of cables, cable ties, etc.

The testing program demonstrated that the tested cable tray configurations possessed substantial seismic capacity. Testing results have shown that existing connections exhibit substantial additional rotational resistance and the Seabrook cable tray systems exhibit highly damped responses. In summary, the

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tests have demonstrated that the tested cable trays and supports can perform their safety functions and maintain their structural integrity when subject to design-basis loads. Therefore, use of these test data to qualify the portion of Seabrook cable tray and supports whose configurations are bounded by those of the tested configurations is acceptable.

(2) Qualification by Envelope Analysis

The staff evaluated the proposed use of envelope analysis to qualify a class of cable tray supports that exhibits similar configurations. Because the analysis method involves development of representative enveloped models and conservative treatment of seismic analysis parameters (e.g., amplified response spectra, tray support height, number of tiers, hardware type, and cable loading), the results obtained should be applicable to the class of supports categorized as belonging to a group. Therefore, the proposed use of the envelope analysis is acceptable, provided the grouping of supports is implemented and documented in a conservative manner.

(3) Qualification by Support-Unique Evaluation

Qualification of support configurations that are not bounded by the Seabrook-specific full-scale tests and not amenable to the use of the envelope analysis are implemented via support-unique analysis. The analytical procedure for such an analysis will comply with the seismic analysis and design criteria previously approved by the staff. As applicable, it will also utilize the support connection performance data obtained from the tests in refining the development of finite element models for the seismic response analysis. Such an approach is acceptable because it ensures that supports thus qualified in conformance with the FSAR acceptance criteria will maintain their safety functions and structural integrity as well as exhibit seismic responses consistent with those observed in the Seabrook-specific system tests.

(4) Use of 20% Damping in Seismic Qualification Analysis

The applicant has demonstrated the applicability of a 20% damping value for Seabrook-specific cable tray supports through full-scale cable tray tests and a comparative study of Seabrook cable tray behavior with that of the Bechtel data-base-tested cable trays. On the basis of the reviews of the technical justifications presented by the applicant, the staff concludes that the use of 20% damping for Seabrook-specific cable tray supports when subject to input acceleration levels of 0.35 g or greater for OBE and SSE conditions is acceptable.

(5) Comparison of Seabrook Cable Tray Seismic Responses With Those of Seismic Experience Data Bases of EQE Inc.

The staff has reviewed Appendix A to the "Cable Tray Support Qualification Program." The appendix provides a comparison of cable tray systems at Seabrook with cable trays in the seismic experience data base compiled by the applicant's consultant, EQE Inc. Staff review found that (a) all parameters associated with the seismic capacity of Seabrook cable trays are enveloped by data base cable trays, (b) most data base cable tray systems have experienced seismic loads comparable to or greater than the seismic design-basis loads for Seabrook cable tray systems, (c) cable tray systems constructed according to normal industry practice have more than sufficient margin to absorb the seismic loads anticipated from moderate earthquakes, such as the Seabrook seismic design-basis loads, and (d) the cable tray systems at Seabrook should have more than adequate capacity to survive the design-basis SSE.

### Documentation

Each particular cable tray support system should have complete documentation to serve as a basis for qualification. This documentation shall also become the design record of that cable tray support system. The documentation should show the basis for qualification either by test, analysis, or combined test and analysis. In the event of qualification by test, the applicability of test data and configuration of cable tray supports should be demonstrated. The applicant should also provide a checksheet for each cable tray support qualified by test and/or envelope analysis. The format of the checksheet should provide for the support identification number, system configurations, loading, bracing, connection, materials used for trays and supports, and support categorization. For cable tray supports qualified by support-unique analysis, the specific information pertinent to modeling, analysis, and design calculations should be documented. In a letter dated June 20, 1986, the applicant agreed to provide documentation and checksheets and advised the staff that the documentation was complete. The documentation shall be in a form suitable for staff audit.

### Amendment of FSAR

The applicant should amend the FSAR to reflect changes as proposed in Attachment 2 to the applicant's letter of December 20, 1985. By letter dated June 20, 1986, the applicant committed to provide this in FSAR Amendment 59.

### Conclusion

The applicant's proposed use of a Seabrook-specific cable tray support qualification program utilizing both test and analysis approaches in lieu of the applicable FSAR criteria previously reviewed and accepted by the staff is acceptable with the above applicant agreed-on commitment to provide (1) full documentation of its basis of qualification for each cable tray support in its installed configuration according to the program proposed in the applicant's letter of December 20, 1985, and (2) an FSAR amendment reflecting the proposed changes listed in Attachment 2 to the applicant's letter of December 20, 1985.

## 3.9 Mechanical Systems and Components

### 3.9.6 Inservice Testing of Pumps and Valves

By letters dated December 31, 1985, and June 4, June 6, June 18, June 23, and June 25, 1986, the applicant submitted an inservice test (IST) program for pumps and valves. The applicant has stated that the IST program will meet the requirements of 10 CFR 50.55a(g), including the 1980 Edition of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Section XI, through Winter 1981 Addenda. The applicant has requested relief from these code requirements pursuant to 10 CFR 50.55a(g)(5) for certain pump and valve tests.

The staff has completed a preliminary review of the IST program. This review includes an evaluation of the applicant's general IST program and of the applicant's request for relief from certain ASME Code requirements for certain pumps and valves. The requests for relief are based on the applicant's determination that ASME Code requirements for certain pumps or valves are impractical within the limitations of design, geometry, and accessibility. The staff will recommend granting the relief where the applicant's request has satisfied the requirements of 10 CFR 50.55a(g)(6)(i). The applicant's relief requests for the specific components are primarily in terms of frequency of testing and the use of alternate test methods and parameters.

On the basis of its review of the IST program, the staff concludes that the general program meets the requirements of 10 CFR 50.55a(g) for low-power (5%) plant operation. The conclusion is based on the knowledge that the pumps and valves are new and have seen little or no wear (therefore, they are expected to be operable when called upon to function), they have been pretested to demonstrate operability, and the minimum interval for inservice testing is 90 days for some of the components. This minimum interval is sufficient time for the staff to meet its commitment to issue a completed safety evaluation on the applicant's IST program. At the time of issuance of the completed safety evaluation, the staff will confirm the IST program is acceptable for licensing for full-power operation.

If during the staff's actions to complete the safety evaluation, certain pumps and/or valves are identified that are not categorized as ASME Code, Class 1, 2, or 3, but perform a safety function, the staff will require that those pumps and/or valves be included in the IST program.

In reviewing the applicant's relief requests, due consideration has been given to the burden on the applicant that could result if certain Code requirements were imposed on the facility. These burdens included the forced shutdown of the plant to perform tests, performing tests on certain components on a 90-day frequency when considerably less frequent testing may be justified, activating spray systems that may be harmful to equipment, and reducing redundancy in safety trains, safety equipment, and safety components during plant operation in order to be able to perform tests imposed by the Code requirements.

The staff finds that interim relief from certain ASME Code requirements will not endanger life or property or the common defense and security of the public and is in the public interest giving due consideration to the burden on the applicant that could result if the requirements were imposed.

## 3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment

### 3.10.1 Seismic and Dynamic Qualification

#### 3.10.1.1 Introduction

Evaluation of the applicant's program for seismic and dynamic qualification of safety-related electrical and mechanical equipment consists of (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general, and (2) an audit of selected equipment items to develop a basis for the judgment of the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program.

Guidance for the evaluation is provided by SRP Section 3.10 (NUREG-0800) and its ancillary documents: RGs 1.61, 1.89, 1.92, and 1.100; NUREG-0484; and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is sufficient to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50; Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100. The program is evaluated by the Seismic Qualification Review Team (SQRT), which consists of engineers from NRC and the Idaho National Engineering Laboratory (INEL, EG&G Idaho).

### 3.10.1.2 Discussion

The SQRT reviewed the equipment dynamic qualification information in FSAR Sections 3.9.2 and 3.10 and visited the plant from November 5 through November 8, 1985, to determine the extent to which the equipment installed at Seabrook Unit 1 meets the criteria described above. A representative sample of safety-related electrical and mechanical equipment as well as instrumentation, in both the nuclear steam supply system (NSSS) and the balance of plant (BOP) scopes, was selected for the audit. Table 3.10-1 identifies the equipment audited. The plant-site visit included field observations of the actual, final equipment configuration and its installation. Observing the field installation of the equipment is necessary to verify and validate equipment modeling used in the qualification program. These observations were followed by a review of the corresponding design specifications and test and/or analysis documents maintained in the applicant's central files. The applicant also provided details of the maintenance, startup testing, and inservice inspection.

The audit identified both generic and equipment-specific concerns. Subsequently, the applicant submitted additional information resolving all of the issues. A summary of the issues and their disposition is presented in the following sections and in Table 3.10-1.

### 3.10.1.3 Generic Items

During the field observation of the nuclear instrumentation system cabinet, the SQRT noted that the clearance between this unit and the adjacent solid state protection system train B was not adequate. The team also learned that this problem was associated with many other cabinets. However, the applicant was aware of the problem and indicated that the problem was being analyzed and its resolution was being actively pursued. In a letter dated July 16, 1986, the applicant confirmed that the generic program for preventing seismic interaction between electrical cabinets is complete, and the resolution was to modify the cabinet configuration to prevent harmful interaction caused by seismic loading. Therefore, this issue is closed.

During the documentation review of the reactor makeup water valve (RMWV-30: NSSS-5), it was discovered that the g-loading assumed for the valve qualification had not been reconciled with the as-built condition. In addition, this had not been done for other valves. However, the applicant indicated that a reconciliation program was in progress. Subsequent documentation provided by the applicant confirmed the completion of this program. Therefore, this issue is closed.

The lifespan of nonmetallic parts for 3-in. air-operated valves had not been evaluated, nor had such an evaluation been performed for many other equipment items. The applicant subsequently submitted documentation providing maintenance and replacement schedules indicating that a program is in place that takes lifespan into account. Therefore, this issue is resolved.

#### 3.10.1.4 Equipment-Specific Item

The SQRT review of the Wyle Laboratories report (44011-1) on the diesel generator relay control cabinet (BOP-16) tests revealed a number of anomalies. These are detailed in the report. The applicant provided additional information noting that the pulling out of the stud will not make it an internal missile, considering its configuration and point of separation. This is acceptable to the staff. Further cracking of insulators did not affect operability. Therefore, this issue is resolved.

#### 3.10.1.5 Confirmatory Items

The Wyle Laboratories tests on the emergency feedwater pump turbine (Terry turbine: BOP-5) revealed many anomalies, some of which appeared to require field modifications. The applicant had to confirm that all the anomalies were satisfactorily resolved.

Subsequent to the SQRT review at the site, the applicant completed the review of new documentation based on a 1979 Terry turbine test and 1985 seismic analysis and found it acceptable with the two following explanations:

(1) The Seabrook turbine has a different governor system precluding the tripping problem.

(2) A support bracket was added to stiffen the lube-oil piping to eliminate the problem of excessive displacement.

The response is satisfactory. This issue is closed.

During the field observation of the emergency feedwater pump turbine (BOP-5), it was found that a temporary 3-in. drain line was installed. It was also reported that the line might become a permanent fix. Subsequent documentation provided by the applicant indicated that the 3-in. drain line is to become a permanent fix and is seismically qualified. This issue is closed.

#### 3.10.1.6 Summary and Conclusion

On the basis of the observation of the field installation, the review of the qualification documents, and the applicant's responses to SQRT's questions during the audit, the staff finds that the applicant's seismic and dynamic qualification program is well defined and adequately implemented. The applicant has demonstrated compliance with the applicable portions of GDC 1, 2, 4, 14, and 30; Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100.

## 3.10.2 Operability Qualification of Pumps and Valves

### 3.10.2.1 Introduction

The NRC staff performs a two-step review of each applicant's pump and valve operability assurance program to determine whether the program can ensure that all pumps and valves important to safety will operate when required for the life of the plant under normal and accident conditions. The first step is a review of FSAR Section 3.9.3.2. However, the information in the FSAR is general in nature and lacks sufficient detail to allow the staff to determine the scope of the overall equipment qualification program as it pertains to pump and valve operability. Thus, the staff also conducts an onsite audit, the second step of the review process.

A Pump and Valve Operability Review Team (PVORT), consisting of engineers from the NRC and INEL, conducts the audit, which reviews a representative sample of installed pump and valve assemblies and their supporting qualification documents at the plant site. On the basis of the results of both the audit and the FSAR review, the PVORT determines whether the applicant's overall program conforms to the licensing criteria in SRP Section 3.10. The applicant must conform to SRP Section 3.10 to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 and Appendix B to 10 CFR 50.

### 3.10.2.2 Discussion

The PVORT reviewed the pump and valve operability assurance information in FSAR Section 3.9.3.2 and conducted an onsite audit to determine the extent to which the pumps and valves important to safety meet the criteria listed above. The results of the FSAR evaluation appeared in the SER (dated March 10, 1983). These were supplemented by specific comments presented at a pre-audit meeting held August 7, 1985. Several of these issues were adequately resolved by the applicant in a letter dated September 24, 1985. The remaining issues were addressed and resolved during the onsite audit.

Table 3.10-2 summarizes the status of the 10 items identified in the SER. The staff has determined (1) that the applicant's position on these items has been adequately clarified and (2) that the applicant has committed to actions that will adequately address the concerns.

The onsite audit, which was conducted November 5 through November 8, 1985, consisted of field observations of equipment configuration and installation for a representative sample of plant equipment. The PVORT selected for evaluation three NSSS and six BOP pump and valve assemblies. Table 3.10-3 summarizes the status of each assembly that was audited. The field observations were followed by a review of the design and purchase specifications, test/analysis documents, and other documents related to equipment operability that are maintained in the applicant's central files. In addition to reviewing information concerning the selected assemblies, the PVORT reviewed information on the plant's overall equipment qualification program. Included within this broad evaluation were those programs and procedures necessary to ensure that equipment qualification issues and concerns will continue to be addressed for the life of the plant. One such program--concerning the deep draft pump issue (refer to IE Bulletin 79-15)--was reviewed in depth.

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The PVORT resolved all but five of the specific operability concerns that were identified. These five concerns follow.

(1) Auxiliary feedwater pump turbine operability with moisture in the steam was not addressed.

(2) The auxiliary feedwater pump turbine end seal was cracked, and the cause had not been determined.

(3) Operability of the auxiliary feedwater pump turbine trip and throttle valve was not ensured after an overspeed trip.

(4) Timing requirements were not addressed for control check valve FW-V-331.

(5) Cooling tower pump SW-P-110A O-ring maintenance procedures were not addressed in accordance with the manufacturer's requirements.

In addition, the applicant was informed of five generic issues that were to be addressed before fuel load. These five issues follow.

(1) Not all of the preservice tests required before fuel load were completed.

(2) Approximately 10% to 15% of all pumps and valves important to safety were not yet qualified and installed.

(3) The plant maintenance procedures were not complete enough for the staff to determine that safety-related equipment will be maintained in its qualified state for the life of the plant.

(4) BOP valves less than 2 in. in size were not included in the Seabrook pump and valve operability assurance program.

(5) The FSAR active valve lists were not current.

These concerns and issues were confirmatory and form the basis for the discussion presented in Section 3.10.2.3 below.

After the site audit, the applicant submitted letters dated December 31, 1985, April 8, 1986, May 1, 1986, and June 13, 1986, which resolved all of the specific issues and four of the generic issues. The remaining generic issue will be verified complete by the Region I staff. The manner in which each confirmatory issue was addressed is briefly discussed in Section 3.10.2.3 and is indicated in Table 3.10-3.

The PVORT has found that the applicant is dealing with the equipment qualification issue in a positive manner. All of the SER items were adequately resolved through additional clarifications and appropriate commitments provided by the applicant. During the audit, the applicant addressed all questions posed by the PVORT and committed to resolve all audit issues before fuel load. Furthermore, the applicant discussed significant aspects of the overall equipment qualification program--such as amplified response spectra reconciliation, equipment modification and reconciliation of original qualification reports, nozzle load verification, and review of non-safety-related equipment located in close proximity to safety-related equipment. Consequently, the PVORT believes that the continuous implementation of the applicant's overall program should provide adequate assurance that the pumps and valves important to safety will operate as required for the life of the plant.

### 3.10.2.3 Confirmatory Issues

On the basis of the PVORT's evaluation of the Seabrook pump and valve operability assurance program, the staff identified to the applicant the following five equipment-specific issues and five generic confirmatory issues that were to be resolved before fuel load:

#### Equipment-Specific Confirmatory Issues

(1) The applicant shall confirm that the auxiliary feedwater pump (FW-P-37A) turbine operability is addressed in regard to the potential of having moisture in the driving steam.

Applicant Response: During hot functional testing, problems were identified involving water slug formation in the steam supply lines to the turbine-driven emergency feedwater (EFW) pump. The applicant explained that design changes were being implemented, which will protect the piping and supports as well as minimize associated problems with the EFW pump turbine. The changes include the addition of drains, resloping lines, adding time-sequenced valves, heat tracing, modification of the turbine governor, and the use of a lower viscosity hydraulic fluid in the turbine governor. The commitment to complete the modifications before fuel load, as well as the onsite review of the qualification documents, provided confidence that the EFW pump turbine will function as required. The staff verified that this commitment has been met.

(2) Before the audit, the turbine end of the auxiliary feedwater pump (FW-P-37A) was found to have a cracked seal. The cause of the seal failure had not been determined nor had steps been taken to prevent a recurrence. The applicant was to confirm that this failure was investigated and resolved.

Applicant Response: After a 48-hour endurance run during hot functional testing, minor leakage was identified at the seal. A dimensional check discovered that the rotor was mismachined in the area of the seal. This machining error prevented the seal from being properly secured to the rotor. The applicant stated that the rotor has been remachined by Ingersoll and is now reinstalled. Retesting before fuel load will verify seal integrity. The staff verified that this commitment was met.

(3) Operation of the auxiliary feedwater pump (FW-P-37A) turbine trip and throttle valve was not investigated when a maximum differential pressure existed across the valve (such as a turbine overspeed trip condition). The applicant was to confirm that the trip and throttle valve can be operated easily during an emergency condition.

Applicant Response: The applicant indicated that during one phase of the plant hot functional tests, the turbine trip and throttle valve was deliberately tripped and manually opened three times. Only one person from plant operations was needed to manually open the valve. During this test the steam inlet pressure was approximately 1100 psig, developing the full differential pressure across the valve. This test demonstration, together with the review of the qualification documents, provides confidence that the valve will perform its safety function as needed. This issue is closed.

(4) Check valve FW-V-331 was changed from a swing check to a control check valve that has specific opening and closing times. The operating times for this control check valve were not addressed in the startup, testing, or operating procedures. The applicant was to confirm that the operating times have been investigated and the timing requirements identified and met.

Applicant Response: The applicant provided several reasons why the in-service test (IST) program will not include closing time requirements for the valve. (1) For the purpose of controlling waterhammer effects, a valve closure time slower than design is acceptable. (2) The valve closure time is not very likely to speed up during its qualified life. (3) The valve closure time requirements were established based upon faulted plant conditions. (4) Any test performed at less than faulted plant conditions will not be meaningful, because the closure times will always be slower than the critical limit. This explanation combined with the onsite review of the qualification documents provides confidence that this component will function as required. This issue is resolved.

(5) The maintenance procedures for the cooling tower pump (1-SW-P-110A) were still in draft form at the time of the audit. The procedures did not address the two O-rings located at the lateral supports for the pump column. The applicant was to confirm that the final maintenance procedures specify the special handling and replacement of the O-rings.

Applicant Response: The applicant has submitted copies of the repetitive task sheets (RTSs) for the service water pump. The implementation of these tasks combined with the onsite discussion of the overall maintenance program adequately resolves this issue.

Generic Confirmatory Issues

(1) At the time of the audit, the maintenance procedures were available for review in draft form only. The applicant was to confirm that the final maintenance procedures will be consistent with the component manufacturer's recommendations. The applicant was to describe how limited-life components are identified, and how the equipment will be maintained in an operable and qualified state for the life of the plant. The applicant was to provide several examples (at least one pump and one valve) of the final maintenance procedures for review.

Applicant Response: The applicant has submitted copies of the RTSs that illustrate the manner by which various maintenance tasks will be performed. Each RTS includes necessary information such as task description, equipment identification, acceptance criteria, references to pertinent vendor procedures, and safety precautions. This material combined with the onsite discussion of the maintenance program adequately resolves this issue.

(2) The applicant was to provide written confirmation in the FSAR that all active BOP valves are covered by the Seabrook pump and valve operability assurance program. In particular, the applicant was to confirm that BOP valves smaller than 2 in. have been included in its valve operability qualification program.

Applicant Response: The appropriate sections of the Seabrook FSAR have been revised by Amendment 56, resolving this generic issue.

(3) At the conclusion of the PVORT audit, it was apparent that a complete list of active valves had not been provided in the FSAR. The applicant was to confirm that all active valves are correctly identified in the FSAR.

Applicant Response: The safety-related BOP and NSSS valves have been identified in FSAR Tables 3.9 (B)-25 and 3.9 (N)-11 by Amendment 56. This issue is resolved.

(4) At the time of the audit, most construction tests had already been completed. However, the hot functional tests were still in progress. The applicant was to confirm that all preservice tests that are required before fuel load have been completed.

Applicant Response: Initially, the applicant committed to complete preservice tests before fuel loading. Subsequently, in Supplement No. 4, the staff noted that, in a letter dated April 8, 1986, the applicant had committed to complete the preservice testing before commercial operation. In a letter dated June 24, 1986, the applicant stated that preservice testing of a component as required by ASME Code, Section XI, will be complete before the component is required to be operable for the mode specified in the Technical Specifications. The staff finds that although this represents a considerable improvement in the schedule for performing and completing the preservice testing, further discussions will be needed before the staff will consider a modification of the requirement to complete all preservice tests before fuel loading. Until such modification has been accepted by the staff, this remains a confirmatory item.

(5) At the time of the audit, approximately 10% to 15% of all pumps and valves important to safety had not been qualified. The applicant shall confirm that all pumps and valves important to safety are properly qualified and installed. In addition, the applicant shall provide written confirmation that the original loads used in tests or analyses to qualify pumps and valves important to safety are not exceeded by any new loads, such as those imposed by a loss-of-coolant accident (LOCA) (hydrodynamic loads) or as-built conditions.

Applicant Response: In a letter dated July 1, 1986, the applicant stated that all pumps and valves requiring qualification are now qualified and are installed in the plant. All required loads have been considered, and as-built conditions have been reconciled to the original design. On the basis of this information, the staff considers this issue resolved.

### 3.10.2.4 Summary

On the basis of the results of (1) the component walkdown and the review of the qualification document packages, (2) the additional explanations and information provided by the applicant throughout the audit, and (3) the resolution of the SER unresolved items, the staff concludes that an appropriate pump and valve operability assurance program has been defined and implemented. The continuous implementation of this overall program should provide adequate assurance that all pumps and valves important to safety will perform their safety-related functions as required for the life of the plant. When the commitments identified in Section 3.10.2.3 have been met, the staff can conclude that the applicant has qualified those pumps and valves important to safety to meet the applicable portions of GDC 1, 2, 4, 14, and 30 (Appendix A to 10 CFR 50), as well as Appendix B to 10 CFR 50.

### 3.10.3 Purge and Vent Valve Operability (TMI Action Plan Item II.E.4.2(6))

Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design-basis accident, is necessary to ensure containment isolation. This demonstration of operability is required by GDC 1, 2, 4, 16, 54, and 56. Guidance for meeting these requirements is provided in SRP Sections 6.2.4 and 3.10.

The staff has reviewed and evaluated the applicant's containment purge and vent valve qualification program with technical assistance provided by Idaho National Engineering Laboratory (INEL). A Technical Evaluation Report prepared by INEL is included as Appendix Q to this supplement. Information that formed the basis of this evaluation included the FSAR and the following applicant submittals: letters dated November 6, 1985, May 13, 1986, and June 4, 1986; "Operability Demonstration of the PSI COP Valves for Public Service Company of New Hampshire, et al.," by Stearns Roger Manufacturers, Inc., dated January 22, 1985; and "Nuclear Seismic and LOCA Analysis," by Posi-Seal International, Inc., dated August 22, 1985. Operability of the applicant's purge valves was based on aerodynamic flow tests that simulated the as-built configuration of the valves and worst-case load combinations. Stress analyses were performed to consider the effects of a combined LOCA and seismic event.

On the basis of its review of the FSAR and test reports concerning the containment on-line purge valves, the staff concludes that the applicant has demonstrated the ability of these valves to close against the buildup of containment pressure following a LOCA or design-basis accident and to provide containment isolation. The applicant's program to demonstrate the operability of the purge valves is acceptable and meets the applicable portions of GDC 1, 2, 4, 16, 54, and 56.

## 3.11 Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment

### 3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is embodied in General Design

Criteria (GDC) 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements the Institute of Electrical and Electronics Engineers (IEEE) Standard 323; and various NRC regulatory guides (RGs) and industry standards.

### 3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews.

The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC asked certain near-term operating license (OL) applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, 10 CFR 50.49, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In conformance with 10 CFR 50.49, electrical equipment for Seabrook Unit 1 may be qualified according to the criteria specified in Category I of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B to 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated August 12, 1983, September 7, 1984, October 31, 1985, April 3, 1986, April 10, 1986, April 16, 1986, April 30, 1986, May 6, 1986, May 7, 1986, June 5, 1986, and June 6, 1986 to supplement the information in FSAR Section 3.11.

The staff has reviewed the adequacy of the Seabrook environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49

and the program for safety-related mechanical equipment. The scope of this report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

### 3.11.3 Staff Evaluation

The staff evaluation included an onsite examination of some equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria in SRP Section 3.11 (NUREG-0800), Revision 2, and in NUREG-0588, Category I, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on February 25, February 26, and February 27, 1986. The audit consisted of a review of 12 files containing information regarding equipment qualification. The staff's findings from the audit are discussed in Section 3.11.4 of this supplement.

### 3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule:

(1) safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(2) non-safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(3) certain postaccident monitoring equipment (RG 1.97, Category 1 and 2 postaccident monitoring equipment).

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

To demonstrate compliance with 10 CFR 50.49(b)(1), the applicant provided a list of systems and their components required to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy line breaks (HELBs). The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of LOCAs or HELBs that have components located in a harsh environment are listed below. This list was reviewed and found acceptable by the staff.

System

(1) auxiliary steam
(2) containment air handling
(3) containment air purge

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(4) control building air handling
(5) containment building spray
(6) component cooling water-primary
(7) combustible gas control
(8) containment on-line purge
(9) rod control and position
(10) chemical and volume control
(11) diesel generator air handling
(12) drains--floor
(13) diesel generator
(14) containment enclosure air handling
(15) electrical distribution
(16) electrical distribution--emergency
(17) emergency feedwater pump house air handling
(18) fuel storage building air handling
(19) feedwater
(20) heat tracing
(21) in-core instruments
(22) miscellaneous equipment
(23) main steam
(24) main steam drain
(25) nitrogen gas
(26) nuclear instrumentation
(27) primary auxiliary building air handling
(28) reactor coolant
(29) residual heat removal
(30) radiation monitoring
(31) reactor makeup water
(32) steam generator blowdown
(33) spent fuel pool cooling
(34) safety injection
(35) sampling
(36) service water
(37) service water pumphouse air handling
(38) vibration monitoring
(39) vents
(40) waste processing--liquid Drains

To demonstrate compliance with 10 CFR 50.49(b)(2) concerning non-safety-related equipment whose failure under postulated accident conditions could prevent the satisfactory accomplishment of safety functions, the applicant included all such equipment in the equipment qualification program. In addition, the applicant has committed to conform with RG 1.75 and will submit his analysis supporting conformance for staff review. The staff will confirm that the applicant conforms to RG 1.75 prior to fuel load. The applicant also performed a review in response to the concerns addressed by the staff in IE Information Notice 79-22, "Qualification of Control Systems," dated September 14, 1979. The staff found the applicant's response to the concerns in IE Information Notice 79-22 acceptable. On the basis of the above, the staff concludes that the applicant's compliance with 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that certain post accident monitoring instrumentation that is located in a harsh environment be included in the equipment environmental qualification program. Guidance as to the matters to be covered

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is contained in R.G. 1.97. R.G. 1.97 identifies parameters to be provided unless adequate justification is given. The applicant has indicated that 10 CFR 50.49(b)(3) equipment is included in the qualification program; however, in addressing conformance with RG 1.97, the applicant identified 10 variables listed in Category 1 or 2 (which specify environmental qualification) of the guide as not requiring monitoring during an accident. That is, the emergency response procedures do not require the plant operating crew to monitor these variables in order to provide a basis for operator actions for mitigating the consequences of an accident.

The staff evaluation of all identified deviations from RG 1.97 is included in Section 7.5.2.4 of this supplement. From the evaluation the staff concludes that sufficient justification has been provided to support the classification of these 10 variables as not being required for accident monitoring. Therefore, these 10 variables, given below, do not fall within the scope of 10 CFR 50.49(b)(3).

(1) primary coolant radiation level
(2) narrow range sump water level
(3) heat removal by containment fan heat removal system
(4) containment sump water temperature
(5) makeup flow-in
(6) makeup flow-out
(7) volume control tank level
(8) boric acid charging flow
(9) accumulator tank pressure
(10) accumulator tank level

Instruments for monitoring variables (1) through (4) are not being installed at Seabrook; although instruments for monitoring variables (5) through (10) are being installed, they will not be qualified for the harsh environment. The staff position is that an instrument to monitor the containment sump water temperature (variable 4) should be provided and that it should be environmentally qualified. In addition, an environmentally qualified instrument should be provided for monitoring either accumulator tank pressure (variable 9) or accumulator tank level (variable 10) although implementation of this position can be deferred to the first refueling without jeopardizing the public health and safety. The basis for this staff position is provided below.

The requirements for accident monitoring instrumentation were issued as Item II.F of NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident." (Revision 2 was issued in August 1980.) NUREG-0737, Supplement 1, "Clarification of TMI Action Plan Requirements," which was issued in January 1983, provides detailed implementation guidance. This supplement, which invokes RG 1.97 as well as other emergency response capabilities, states that it is not intended that the guidance documents referred to (in this instance, RG 1.97) are to be used as requirements, but rather that they are to be used as sources of guidance for NRC staff and licensees regarding acceptable means for meeting the basic requirements. Similarly, footnote 4 to 10 CFR 50.49(b)(3) states that specific guidance concerning the types of variables to be monitored is provided in Revision 2 of RG 1.97. Engineering judgment is required in the application of this guidance. Equipment qualification for instrumentation identified on a plant-specific basis as not required for accident monitoring would not fall

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under the provisions of 10 CFR 50.49(b)(3) but rather under the provisions of RG 1.97 relating to other instrumentation.

Revision 2 of RG 1.97 identifies three basic types of equipment: accident monitoring instrumentation, systems operation monitoring instrumentation, and effluent release monitoring instrumentation. Additionally, the guide identifies variables, types A through E, to distinguish the types of parameters and to provide a general ranking of their importance. Accident monitoring instrumentation provides information on vital parameters classified as type A, B, and C variables in Table 2 of the regulatory guide.

Type D variables provide information to (1) indicate operation of individual safety systems and other systems important to safety and (2) help the operator make appropriate decisions in mitigating the consequences of an accident. Of the 10 variables identified above, 9 are Type D. The staff's position is that these 9 variables are not required to perform either of these functions. The remaining variable, narrow range sump water level, is type B. However, a fully qualified wide range sump level instrument is installed to provide this variable; therefore, a narrow range instrument is not considered necessary and need not be provided.

However, sump water temperature is a parameter, along with sump level and containment pressure, that influences net positive suction head (NPSH) for safety system pumps during the recirculation mode. Furthermore, knowledge of sump water temperature is useful in performing postaccident energy balance calculations. RG 1.97 identifies containment sump water temperature instrumentation as equipment that should be environmentally qualified. Thus, even though this variable is not required for the performance of the two function attributes of type D variables, the information it provides is deemed of sufficient usefulness following an accident that a fully qualified instrument should be provided.

The accumulator tank level and pressure provide direct indication of functioning of the accumulators (first-line safety equipment) during an accident. Either pressure or level indication would be sufficient to indicate discharge of the accumulators. It is recognized that the accumulators are passive systems; that the operator could take no meaningful action to restore an inoperable accumulator other than to open a closed (inadvertently) isolation valve for which qualified status information is provided; and that other variables (e.g., reactor system pressure, reactor vessel level and core temperature) are available from which operation of the accumulators can be inferred. However, even though accumulator pressure or level are not required for performance of the function attributes of type D variables, the direct indication of accumulator operation is deemed of sufficient usefulness that a fully qualified pressure or level instrument should be provided.

In summary, the staff's position is that environmentally qualified instrumentation for monitoring accumulator pressure (or level) and containment sump water temperature should be installed before startup from the first refueling since this is not a required post accident monitoring instrumentation. This is not inconsistent with 10 CFR 50.49(b)(3). The staff discussed this position with the applicant. The applicant agrees with the staff position and, by letter dated June 6, 1986, the applicant committed to meet it.

### 3.11.3.2 Qualification Methods

#### 3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed criteria for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in NUREG-0588 are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

The staff has reviewed the methods used by the applicant to demonstrate qualification and concluded that they are in compliance with the requirements of NUREG-0588, Category I.

#### 3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records," and 4, "Environmental and Missile Design Bases," and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Section III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualification:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.
- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.
- Design control measures shall be established for verifying the adequacy of design.
- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, qualification documentation for three items of safety-related mechanical equipment has been submitted by the applicant and has been reviewed by the staff. The staff review has verified that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed.

### 3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be used for determining the environmental conditions associated with LOCAs or HELBs, inside or outside of containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the environmental conditions established by the applicant.

In December 1984, the NRC issued IE Information Notice 84-90 regarding a potential problem pertaining to plant analysis and equipment qualification with respect to a postulated main steamline break (MSLB) with release of superheated steam. It was discovered during the NRC staff's review of the Westinghouse

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methodology for computing mass and energy releases for a postulated MSLB that the heat transfer from the uncovered portion of the steam generator tube bundle was not included. In the FSAR, the applicant used this Westinghouse steam generator blowdown model (i.e., the Westinghouse methodology of computing mass and energy releases) for calculating equipment qualification temperature inside containment. By letter of April 10, 1986, the applicant reported its evaluation of the impact of the superheated steam blowdown on the equipment qualification temperature previously calculated for both inside and outside containment.

The applicant's evaluation for equipment inside containment was based on Westinghouse Topical Report WCAP-8822, Supplement 2, in which it was found that the impact of steam superheating is not significant for large dry containments. In Supplement 2 of WCAP-8822, a modified LOFTRAN code, accounting for heat transfer to the steam during steam generator tube uncovery, was used to calculate mass and energy release rates following an MSLB. The modification was described in Supplement 1 of WCAP-8822. The staff has reviewed both Supplements 1 and 2 of WCAP-8822 and found them acceptable.

Furthermore, the applicant stated that the results of WCAP-8822, Supplement 2, are applicable to the Seabrook Model F steam generator. On the basis of the above evaluation, the staff concludes that the environmental qualification pressure and temperature inside containment, established previously in the FSAR, are still valid.

### 3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside Containment

The applicant provided the LOCA/MSLB profiles used for equipment qualification program submittals. The peak values resulting from these profiles are as follows:

| | Maximum Temperature | Maximum Pressure | Humidity |
|---|---|---|---|
| LOCA/MSLB | 370.0°F | 34.5 psig | 100% |

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; that is, there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

### 3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside Primary Containment

The applicant has provided, in the FSAR, the temperature, pressure, and humidity conditions resulting from HELBs in various compartments outside containment. The criteria used to define the location of the HELBs are described in the FSAR Section 3.6. As a result of the superheated steam issue described in Section 3.11.3.3, the applicant determined that the new mass and energy releases into the two main steam and feedwater pipe chase areas are greater than the previously postulated releases. Therefore, the maximum temperature in the faulted pipe chase is expected to be higher than the previously prescribed temperature for environmental qualification of equipment in the pipe chase.

In letters dated April 10, 1986, and June 5, 1986, the applicant stated that despite any postulated superheated temperature in the faulted pipe chase, the Seabrook plant can achieve a safe shutdown. Seabrook has two separated main steam and feedwater pipe chase areas on the east and west sides of containment. Each pipe chase houses the feedwater and main steam piping for two of the four steam generators. The pipe chase also houses the main steam and feedwater isolation valves, steam safety relief valves, atmospheric dump valves, and main steam supply valves to the emergency feed pump turbine.

Given an HELB in one of the pipe chase areas, the applicant stated that the main steam isolation valves and the other electrical equipment in the faulted pipe chase will perform the intended safety functions before the tubes in the faulted steam generator are uncovered and superheated steam is generated. The applicant also evaluated all of the electrical equipment in the faulted pipe chase and determined that its consequential failure could not affect the ability to safely shut down Seabrook with the equipment in the other pipe chase. The staff finds this approach acceptable because only two steam generators are required to safely shut down the Seabrook plant.

However, if the superheated steam should cause the main steam isolation valves to fail in the faulted pipe chase, two steam generators would blow down. This event was not previously evaluated in FSAR Chapter 15. The applicant provided the results of a scoping analysis for a two-steam-generator blowdown event.

The FSAR Chapter 15 steamline break analysis is based on a minimum assumed shutdown margin of 1.3% and is performed at conditions representative of end of life (EOL). A Westinghouse steamline break topical report (WCAP-9226, Rev. 1) provides sensitivity studies as a function of the moderator coefficient for the steamline break event which demonstrate that as the temperature coefficient becomes less negative, the accident becomes much less limiting. Since at beginning of life (BOL) the temperature coefficient is less negative, the BOL case is significantly less limiting than the point at which the analyses are performed. The amount of reactivity added by the consequential opening of both main steam isolation valves (MSIVs) is very small and would have a negligible effect on the BOL transient as compared with the FSAR (EOL) transient. On this basis, it is Westinghouse's conclusion that the departure from nucleate boiling (DNB) design basis for the plant would be maintained at BOL assuming a shutdown margin of 1.3%.

At EOL, the consequential opening of both MSIVs could potentially result in a transient more severe than that in the present FSAR analysis. However, the Seabrook Cycle 1 nuclear design calculated shutdown margin at EOL is greater than 3.8% after taking into account uncertainties. This value includes the assumption that all rods are fully inserted except for the stuck rod. WCAP-9226 presents the results of sensitivity studies that show that the transient is less limiting as the initial shutdown margin increases. Representative calculations incorporating consequential MSIV failures due to superheated steam show that the amount of reactivity added by the consequential opening of the MSIVs is negligible when compared with the negative reactivity available by the inclusion of the Cycle 1 shutdown margin of more than 3.8% in the analysis. Therefore, the DNB design basis would be met at EOL when credit is taken for the Cycle 1 specific value of shutdown margin.

In Section 15.6.4 of the SER, the staff reviewed the radiological consequences of a main steamline failure outside containment. This analysis was based on the blowdown of one steam generator. The staff has performed an independent calculation of the radiological consequences of a main steamline failure as described in Section 15.6.4 of the SER, assuming a second steam generator also blows down outside containment with an additional iodine inventory loss to the atmosphere of about 5 curies within the first 2 hours of the accident. This release will increase the exclusion areas boundary dose to the thyroid by about 0.6 rem with no noticeable increase in the whole-body dose. Even with this increase, the calculated dose for a two-steam-generator blowdown accident would be a small fraction of the 10 CFR 100.11 dose guidelines.

Therefore, on the basis of the above discussion, the staff concludes that the Seabrook plant can safely shut down following an HELB in either pipe chase. In addition, the Seabrook plant meets the requirements of GDC 28 of Appendix A to 10 CFR 50 and the guidelines of 10 CFR 100.11 provided that the Seabrook Technical Specifications require a 3.8% ΔK/k shutdown margin for operating modes 1, 2, and 3. In a letter dated June 5, 1986, the applicant committed to modify the Seabrook Technical Specifications to require a 3.8% ΔK/k shutdown margin in operating modes 1, 2, and 3. The staff finds this acceptable.

### 3.11.3.3.3 Submergence

The submergence potential has been determined by the applicant to be below (-)20 ft 8 in. inside the containment and at various elevations in buildings outside the containment building. The applicant has taken appropriate corrective actions to either justify submerged operation, or to relocate or qualify the affected equipment.

### 3.11.3.3.4 Chemical Spray

A chemical spray inside containment may be used to mitigate the effects of an accident. The applicant has appropriately included this parameter in the evaluation of equipment located inside containment.

### 3.11.3.3.5 Aging

The aging program requirements for Seabrook electrical equipment are defined in Category I of NUREG-0588. All degrading influences must be considered and included in the aging program. Justification for excluding preaging of equipment in type testing must be established on the basis of equipment design and application, or on state-of-the-art aging techniques. A qualified life is to be established for each equipment item.

In addition to the above, a maintenance/surveillance program must be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. The applicant committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American Nuclear Society/American National Standards Institute Standard ANS-3.2/ANSI N18.1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment.

Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate.

The staff found that the applicant has adequately described a program that incorporates the above guidelines. In addition, the applicant has stated that the maintenance/surveillance program is in effect at Seabrook.

#### 3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values for the radiation levels postulated to exist following a LOCA. The application and methodology to determine these values were presented to the applicant in NUREG-0588 and NUREG-0737. The staff review determined that the values to which equipment was qualified enveloped the requirements identified by the applicant.

The maximum value specified by the applicant for use in equipment qualification inside containment, and in areas outside containment exposed to post-LOCA recirculating fluid environments, is $2.0 \times 10^8$ rads (gamma plus beta). This value is acceptable for use in the qualification of equipment.

### 3.11.3.4 Outstanding Equipment

The Seabrook qualification program has a total of 112 item groups. The applicant originally committed to qualify all equipment for a postaccident operability time of 1 year. Subsequently, the applicant discovered that there are 12 item types (i.e., 12 item types out of the 112 item groups) that cannot be qualified for a postaccident operating time of 1 year. The staff typically requires qualification for a period of 100 days after an accident, and in some instances the regulations allow for postaccident qualification periods substantially less than 100 days. Table 3.1 lists the 12 item types and their postaccident qualification periods as provided by the applicant.

The staff reviewed the qualification information provided by the applicant for the 12 item types listed in Table 3.1 in which the applicant indicated that 5 of the 12 item types met the staff requirement of 100 days and the remaining 7 meet the postaccident time margin requirements specified in Position C.4 of Revision 1 of RG 1.89. Therefore, the staff finds this acceptable.

## 3.11.4 Environmental Qualification Audit

On February 25, February 26, and February 27, 1986, the staff, with assistance from EG&G Idaho, Inc., conducted an audit of the applicant's qualification files and equipment installed at the plant. Twelve files were audited to determine if the documents in the qualification files supported the qualification status determined by the applicant.

The files selected for audit were

(1) Okonite Cable (File No. 113-03-01)
(2) Transamerica Level Transmitter (File No. 174-15-01)
(3) Brandrex Cable (File No. 113-06-01)
(4) Reliance Motor (File No. 236-11-06)
(5) Limitorque Motor Operator (File No. 248-37-01)
(6) ASCO Solenoid Valve (File No. NSSS-220-02)
(7) ITT-Suprenoit Cable (File No. 113-19-01)
(8) Conax Conduit Seal Assembly (File No. 118-03-01)
(9) Rotork Motor Operator (File No. 173-05-02)
(10) Barton Transmitter (File No. 252-16-02)
(11) Endevco Accelerometer and Charge Converter (File No. 252-30-01)
(12) Weidmiller Terminal Block (File No. 600-02-01)

Several deficiencies were noted and discussed with the applicant at the time of the audit and transmitted to the applicant by letter dated April 10, 1986. The applicant proposed acceptable corrective measures in the form of additional information and file revision to eliminate the deficiencies cited.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify that the manufacturer, model number, location, and installation are consistent with qualification documents. The applicant proposed acceptable corrective measures for the deficiencies that were found and committed to correct all deficiencies by fuel load.

### 3.11.5 Conclusions

The staff has reviewed the Seabrook program for the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment. The purpose of the review was to determine the adequacy and scope of the qualification program and to verify that the methods used to demonstrate qualification are in compliance with applicable regulations and standards.

On the basis of the results of its review and subject to confirmation that all audit deficiencies have been corrected, the staff concludes that the applicant has demonstrated compliance with the requirements for environmental qualification as outlined in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections III, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria as specified in NUREG-0588.

Table 3.10-1 Summary of SQRT audit

| Item no. | Description | Applicant ID no. | Safety function | Review findings | Resolution | Status |
|---|---|---|---|---|---|---|
| NSSS-2 | 3-in. air-operated globe valve | LCV-459 | Safety function moved to another valve; SQRT reviewed qualification for pressure containment. | | | Qualified |
| NSSS-3 | Safety injection system accumulator tank | SI-TK-9A | Provides storage for emergency core cooling water. | Base anchor bolts smaller than those used to qualify the tank. | Independent analysis by UE&C showed smaller bolts have adequate strength. | Qualified |
| NSSS-4 | Electric hydrogen recombiner power supplies | | Provide power supply for electric hydrogen recombiner for containment hydrogen removal after a loss-of-coolant accident. | | | Qualified |
| NSSS-5 | Reactor water makeup valve | RMW-V-30 | Provides containment isolation. | 1. Assumed g-load not reconciled with as-built condition (generic). | 1. Done. | Qualified |
| | | | | 2. Lifespan of nonmetallic parts not evaluated; clearance inadequate (generic). | 2. Done. | |
| NSSS-6 | 8-in. motor-operated gate valve | RHR-8716A, B | Provides shutoff for the residual heat removal system. | | | Qualified |
| NSSS-7 | Reactor trip switchgear | CP-CP-111 | Provides reactor trip safety function. | | | Qualified |
| NSSS-8 | Reactor vessel level information system 8086 cabinets | MM-CP-486A | Provide reactor vessel liquid level information after a seismic event. | Cabinets not installed. | SQRT reviewed installation drawings and considered them adequate. | Qualified pending proper installation |
| NSSS-11 | Nuclear instrumentation system cabinet | RP | Provides alarm function; as secondary control function, indicates reactor status during startup, power operation; overpower trip protection. | Clearance from adjacent cabinets inadequate (generic). | To be handled on a generic basis. | Qualified |
| NSSS-12 | Safeguards test cabinet | MM-CP-14, 15 | Supplies power to the control panel. | | | Qualified |

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Table 3.10-1 (Continued)

| Item no. | Description | Applicant ID no. | Safety function | Review findings | Resolution | Status |
|---|---|---|---|---|---|---|
| NSSS-13 | Instrument bus power switch: static inverter | EDE-I-1A | Supplies power to the instrument bus distribution panel that provides power to instrumentation monitoring and indicating plant parameters. | Auditable link between the test report model and the field model missing. | Subsequently provided. | Qualified |
| BOP-1 | 36-in. butterfly valve | CAP-V-1, 4 | Isolates the containment. | Model number not on the valve; therefore, could not be compared with that shown on the long form. | Correct model number has been attached and traceability has been established. | Qualified |
| BOP-3 | Control switch | CP-CS-6601-1 | Trips the reactor manually from the main control board. | | | Qualified |
| BOP-4 | Computing device | EDE-AY-9700, 9710 | Converts signal for monitoring diesel generator output current for postaccident monitoring. | Site-specific required response spectra (RRS) exceed Westinghouse's generic RRS. | Requalification was completed; device was found acceptable. | Qualified |
| BOP-5 | Emergency feedwater pump and turbine | FW-TD-2, FW-P-37A | Provide emergency feedwater to the steam generator. | 1. A substantial number of anomalies to be resolved.<br>2. Temporary 3-in. line must be seismically qualified. | 1. Done.<br>2. Done. | Qualified |
| BOP-6 | 4-in. motor-operated globe valve | MS-V-204, 205 206, 270 | Provides isolation function in a 4-in. bypass line around the main steam isolation valves. | | | Qualified |
| BOP-7 | Neutron flux signal processor | NI-NM-6690, etc. | Indicates the neutron flux and shutdown margin to the operator. | Model number did not match that on the long form. | The supplier changed the model number, but the equipment is the same | Qualified |
| BOP-11 | Vibration monitoring control panel | VB-CP-299, VB-YM-6832 | Indicates the position of the pressure relief valves to the operator; the recorder has no safety function. | Model number not shown on the panel; could be found only by referring to the drawing. (The number on the drawing was the one shown on the long form.) | Properly tagged and traceability established. | Qualified |

Table 3.10-1 (Continued)

| Item no. | Description | Applicant ID no. | Safety function | Review findings | Resolution | Status |
|---|---|---|---|---|---|---|
| BOP-14 | 18-in. feedwater isolation valve | FW-V-30 | Provides containment isolation for the feedwater piping. | Valve operator test specimen had some test anomalies related to O-ring seal design. | Seals were redesigned to eliminate leakage problems. | Qualified |
| BOP-15 | 6-in. motor-operated gate valve | CBS-V-38 | Provides shutoff for the containment spray system. | | | Qualified |
| BOP-16 | Diesel generator relay control panel | DG-CP-36, 37 | Provides a control function for the diesel generator. | Adequate justification not provided for two test anomalies. | Applicant provided adequate justification for these anomalies. | Qualified |
| BOP-17 | Pressure switch | DGA-PS-OPL-1 | Regulates lube oil flow to the diesel engine. | Qualification briefly reviewed to see that a complete qualification package was available. | Complete. | Qualified |

Table 3.10-2 Status of pump and valve operability assurance items

| SER items[1] | Finding/ resolution | Status |
|---|---|---|
| Based on the summaries in FSAR Tables 3.9(B)-14 and 18 (Amendment 53), it is not clear if the applicant has completely qualified the emergency feedwater and fuel oil transfer pumps. The applicant should provide the appropriate information in each table to demonstrate that these pumps are qualified in a manner consistent with FSAR Section 3.9(B).3.2a (Amendment 53). | Satisfactory | Closed[2] |
| It is not clear from FSAR Table 3.9(B)-2 and Section 3.9(B).3.1 (Amendment 48) that loss-of-coolant accident (LOCA) loads have been specified in the design load combinations for balance-of-plant (BOP) Class 1 components and supports. The applicant should confirm that LOCA loads have been applied to the appropriate BOP equipment in a manner similar to that given in FSAR Section 3.9(N).1.6 for nuclear steam supply system (NSSS) equipment. | Satisfactory | Closed[3] |
| FSAR Section 3.9(B).3.2b (Amendment 48) describes operability assurance for active BOP valves 2 in. and larger. The applicant should include all sizes of active BOP valves in the operability assurance program. | Satisfactory | Closed[3] |
| The applicant should provide specific information for the BOP pumps and valves similar to the information provided in FSAR Tables 3.9(N)-10 and -11 for NSSS pumps and valves. | Satisfactory | Closed[2] |
| FSAR Table 3.9(B)-2 (Amendment 47) summarizes the load combinations for Class 1, 2, and 3 BOP components and supports. The applicant should identify the stress criteria used to qualify Class 1 BOP valves. | Satisfactory | Closed[2] |
| FSAR Tables 3.9(B)-3 and 3.9(N)-7 provide the stress criteria for Class 2 and 3 nonactive BOP and NSSS pumps, respectively. The applicant should identify these nonactive pumps. | Satisfactory | Closed[2] |
| The applicant should clearly show the extent to which RG 1.148, ANSI/ASME N551.1 draft standards, and ANSI B16.41 are met. | Satisfactory | Closed[3] |

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See footnotes at end of table.

Table 3.10-2 (Continued)

| SER items[1] | Finding/ resolution | Status |
|---|---|---|
| The applicant should clarify the methods used for qualification. Specific information should be presented in the FSAR, and be available for review at the site. The applicant should demonstrate:<br>• The extent to which operational testing is performed at design-basis conditions (full flow, pressure, temperature, etc.).<br>• The technical basis for qualifying equipment by similarity analysis and prototype testing.<br>• Qualification of the equipment as an assembly rather than individual components. | Satisfactory | Closed[3] |
| The applicant should clearly show how implementation of the initial test program, maintenance and surveillance, inservice inspection, and quality assurance programs will maintain equipment operability throughout the 40-year plant life. Specific criteria should be presented in the FSAR, and be available for review at the site. | Satisfactory | Closed[3] |
| The following actions by the applicant would enhance the staff's understanding of the plant:<br>• The terms "DSL" and "LOCA DISPL" in FSAR Table 3.9(B)-6 (Amendment 48) should be defined.<br>• The seismic accelerations discussed in FSAR Section 3.9(B)3.2a should be specified, and how they were used to qualify "rigid" and "flexible" BOP pumps should be described.<br>• FSAR Sections 3.9(B)3.2b and 3.9(N)3.2a(2) describe BOP and NSSS programs for testing valves of various designs and sizes during simulated faulted conditions. The criteria used to select the valves for testing and the range of sizes that are covered should be discussed. | Satisfactory | Closed[2] |

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See footnotes at end of table.

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Table 3.10-2 (Continued)

| SER items[1] | Finding/ resolution | Status |
|---|---|---|
| • Confirm that the evaluation of NSSS check valves will include "stress analysis of critical parts which may affect operability, including faulted condition loads," as is the case for BOP check valves. | | |

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[1] Items were identified in the SER and supplemented by specific comments presented at a pre-audit meeting on August 7, 1985.

[2] This item was adequately resolved on the basis of information submitted by the applicant in a letter from R. Sweeney, Bethesda Office Manager Seabrook Station, to V. Nerses, NRC Seabrook Project Manager, dated September 24, 1985, entitled "Advance Copies of Annotated FSAR Pages and System Turnover Status."

[3] This item was adequately resolved on the basis of information reviewed by the staff during the site audit on November 5-8, 1985. The applicant committed to close out this item in a manner and time that are acceptable to the staff.

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Table 3.10-3 Summary of PVORT audit

| Plant ID no. | Description | Safety function | Findings | Resolution | Status | Remarks |
|---|---|---|---|---|---|---|
| FW-P-37A (BOP) | Turbine-driven auxiliary feedwater pump | Provides feedwater to the steam generator if normal feedwater is not available. | a,b,c | d | Closed | Findings "a" and "c" were resolved by applicant's April 8, 1986, letter. Finding "b" was resolved by applicant's June 13, 1986, letter. |
| FW-V-331 (BOP) | Main feedwater to steam generator B isolation check valve | Isolates the feedwater header if feedwater is lost. | e | d | Closed | Operating time of this valve is important to safety. Timing requirements were not addressed. This issue was resolved by applicant's April 8, 1986, letter. |
| CC-V-975 (BOP) | Primary component cooling water to radiation monitor isolation valve | Isolates the radiation monitor when full primary containment cooling water flow is required by safety-grade equipment. | | | Closed | Specific concerns were resolved during the audit. |
| FW-V-48 (BOP) | Steam generator C feedwater containment isolation valve | Closes on containment isolation signal. | | | Closed | Specific concerns were resolved during the audit. |
| CC-V-122 (BOP) | Primary component cooling water return isolation from non-safety-grade components | Closes on isolation signal. | | | Closed | Specific concerns were resolved during the audit. |
| SW-P-110A (BOP) | Cooling tower pump A | Provides cooling water flow when the cooling tower is used as the ultimate heat sink. | f | d | Closed | Two O-rings are used to control lateral support of pump column. O-rings should be maintained for life of plant. This issue was resolved by applicant's April 8, 1986, letter. |
| CS-P-28 (NSSS) | Centrifugal charging pump B | Provides borated and makeup water as well as high-head safety injection. | | | Closed | Specific concerns were resolved during the audit. |
| RC-V-456A (NSSS) | Pressurizer power-operated relief valve | Opens to prevent a reactor trip due to overpressure of pressurizer. | | | Closed | Specific concerns were resolved during the audit. |
| RH-V-14 (NSSS) | Cold-leg injection residual heat removal return line isolation valve | Closes for containment isolation and hot-leg recirculation. | | | Closed | Specific concerns were resolved during the audit. |
| -- | All pumps and valves important to safety | Operate as required during the life of the plant under normal and accident conditions. | g,h,i,j,k | d | Closed | All generic issues were resolved by applicant's April 8, 1986, letter. |

See footnotes that follow table.

Table 3.10-3 (Continued)

a. Turbine operation when moisture is mixed with the steam was not investigated; turbine operation with moisture in the steam must be addressed (specific).

b. The turbine trip and throttle valve was not installed in a way that ensured easy operation. Easy operation of the trip and throttle valve with a maximum differential pressure across the valve (for example, a turbine overspeed condition) was not demonstrated. Easy operation of the trip and throttle valve must be investigated (specific).

c. The turbine end pump seal was found to be cracked. The cause of the cracked pump seal needs to be investigated and resolved (specific).

d. At the conclusion of the site audit, the staff summarized the remaining open issues. The applicant was informed of the appropriate actions necessary to resolve the specific and generic confirmatory issues before fuel load (specific).

e. This valve was changed from a swing check valve to a control check valve that has specific opening and closing times. The operating times were not addressed in the startup, testing, or operating procedures. The applicant shall confirm that the operating times have been investigated and the timing requirements identified and met (specific).

f. The maintenance program did not include procedures for replacing the O-rings per manufacturer's recommendations. The maintenance program should include procedures for maintaining the qualification status of the O-rings for the life of the plant (specific).

g. Maintenance procedures were in a draft form and generally not available for review. The applicant shall confirm that all final maintenance procedures are consistent with manufacturer's requirements. The applicant shall describe how limited-life components are identified. The applicant shall provide examples of maintenance procedures for review (generic).

h. BOP valves smaller than 2 in. were not included in the FSAR active valve list. The applicant shall confirm that the FSAR BOP list addresses valves less than 2 in. (generic).

i. The active valve lists in the FSAR were not complete. The applicant shall confirm that all active pumps and valves are included in the FSAR active component lists (generic).

j. All preservice tests have not been completed. The applicant shall confirm that all preservice tests that are required before fuel load have been completed (generic).

k. The applicant has not completed the qualification of all pumps and valves important to safety. The applicant shall confirm that all pumps and valves important to safety are qualified before fuel load (generic).

Table 3.1 Equipment item types and thier postaccident qualification periods

| EQ file number | Description | Qualified post-accident operating time | Time required to perform safety function | Number of items |
|---|---|---|---|---|
| 174-00-01 | Foxboro transmitters | 100 days | 90 days | 13 |
| 252-38-01 | ASCO temperature switches | 160 days | 30 days | 4 |
| 600-01-04 | Raychem 8-kV motor connector kits | 100 days | 30 days | 13 |
| 173-05-03 | Maisoneilan E/P converter | 204 days | 100 days | 4 |
| 248-36-01 | Borg-Warner feedwater isolation valves | 4 hours | Approximately 1 minute | 4 |
| 600-06-01 | NAMCO EC 210 series conduit seals | 318 days | 30 days | 16 |
| 113-03-01 | Okonite 600-V power cable* | 30 days | 24 hours | |
| 113-17-01 | Anaconda 600-V control cable* | 30 days | 24 hours | |
| 113-18-01 | Anaconda 300-V instrumentation cable* | 30 days | 24 hours | |
| 113-20-01 | ITT Suprenant 300-V instrumentation cable* | 30 days | 24 hours | |
| 172-01-01 | General Atomic Radiation Monitors and Detectors (annulus) | 2 hours | Approximately 2 minutes | 1 |
| 172-01-01 | General Atomic Radiation Monitors and Detectors (inside containment) | 7 hours | Approximately 2 minutes | 2 |

*Only the cable that is subject to submergence is limited to 30 days' qualification. This applies to all cable listed here.

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# 4 REACTOR

## 4.4 Thermal-Hydraulic Design

### 4.4.5 Instrumentation

#### 4.4.5.3 Loose Parts Monitoring Systems

In the SER, the staff stated that the applicant's loose parts monitoring system (LPMS) was similar to the LPMS at the Shoreham nuclear plant, which was approved by the NRC staff. The applicant committed to provide a detailed equipment description demonstrating compliance with RG 1.133. This was submitted in Amendments 55 and 56 to the FSAR and provided information including the following.

The LPMS will consist of 12 active instrumentation channels, each comprising a piezoelectric accelerometer (sensor), signal conditioning equipment, and diagnostic equipment. Two redundant sensors are fastened mechanically to the reactor coolant system at each of the following potential loose parts collection regions:

(1) reactor pressure vessel--upper head regions
(2) reactor pressure vessel--lower head region
(3) each steam generator--reactor coolant inlet region

The system will be capable of detecting a metallic loose part that weighs from 0.25 lb to 30 lb impacting in the vicinity of six natural collection regions having a kinetic energy of 0.5 ft-lb on the surface.

The system is designed to remain functional for a seismic event up to and including the operating-basis earthquake.

The staff has found that the applicant's submittal describing compliance of the LPMS with RG 1.133 is acceptable because the applicant has satisfactorily addressed the specific positions of Section C and has not requested any deviations.

Section C.3 of RG 1.133 states that alert levels for startup and power operation have to be established and must be submitted to the NRC staff in a final baseline report within 90 days following completion of the startup test program.

The applicant has committed (letter from J. DeVincentis, PSNH, to V. Noonan, NRC, dated April 8, 1986) to provide, before power operation, a final baseline report that will contain (1) an evaluation of the LPMS for conformance to RG 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors"; (2) a description of the system hardware, operation, and implementation of the loose parts detection program, including the plans for startup testing, acquisition of baseline data, and alarm settings; and (3) a description and evaluation of diagnostic procedures used to confirm the presence of a loose part. The applicant has stated in FSAR Amendment 55 that a training program will be provided to give pertinent general and specific

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training for plant personnel involved with system operation, maintenance, and loose part diagnosis before station operation. This is acceptable to the staff.

On the basis of the applicant's conformance with RG 1.133 including its commitment to supply the baseline report following startup testing, the staff concludes that the LPMS for Seabrook is acceptable.

### 4.4.5.4 ICC Instrumentation

On November 4, 1982, the Commission determined that instrumentation system for detection of inadequate core cooling (ICC) consisting of upgraded subcooling margin monitor, core exit thermocouples, and a reactor coolant inventory tracking system is required for the operation of pressurized-water-reactor facilities. The requirements of the instrumentation system for the detection of ICC are delineated by NUREG-0737, Item II.F.2. The applicant responded by submitting design information, revised FSAR pages, emergency operating procedure guidance, and design analysis and test data in a letter dated February 24, 1986. Technical Specifications covering ICC are undergoing a separate review as part of the overall Seabrook Technical Specification review. The applicant states that emergency operating procedures when written will conform to approved emergency response guidelines. A separate review of emergency operating procedures is conducted only if the applicant deviates from the approved guidelines. The Seabrook ICC monitoring system will be installed and tested before fuel is loaded and will be calibrated before the plant achieves 5% power.

The ICC monitoring system installed at Seabrook Station includes

(1) core exit thermocouple monitoring
(2) core subcooling margin monitoring
(3) reactor vessel level monitoring

The incore thermocouple/core cooling monitor has been installed to provide improved information presentation and display to the plant operators on the status of core heat removal capability. The system monitors all core exit thermocouples and calculates core subcooling margin utilizing redundant channels of instrumentation and control room displays.

The core exit temperature monitoring system is a part of the incore instrumentation system, which consists of 58 thimble assemblies, each with 5 fixed neutron detectors and 1 Type K chromel-alumel thermocouple at fixed core outlet positions. The core exit thermocouple monitoring system uses two redundant, independent trains that monitor all 58 of the Seabrook Station chromel-alumel core exit thermocouples (29 on train A and 29 on train B). The analog indicator displays the third highest valid thermocouple temperature. The train and quadrant orientation of the thermocouples were provided by the applicant. The core exit thermocouple leads leave the core through the bottom of the reactor vessel. After leaving the vessel, they are routed for mating with the extension wires (cables) through the seal table where the thermocouple leads are terminated with qualified connectors. The applicant stated that, beyond the seal table, the cables are routed to the containment penetrations in a manner consistent with RG 1.75. The uncompensated core exit thermocouple signals (29) for each train are then sent to their respective ICC monitors, which house the reference junctions. The thermocouples have a range of 0° to 2300°F. The thermocouple

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information is provided as an output on two redundant plasma displays, which serve as both the primary and backup displays.

The subcooling margin monitor calculates the margin to saturation temperature using wide-range reactor coolant system pressure and a core exit temperature value based on the auctioneered high thermocouple quadrant average temperatures. This represents bulk loop temperature and is consistent with the Westinghouse Owners Group Emergency Response Guidelines. The subcooling margin calculated values are routed to redundant plasma displays and analog indicators. The applicant stated that the cable routing from sensor input to display meets RG 1.75.

The upper and lower range limits of the core subcooling calculation are adjustable up to a reactor coolant system pressure of 3000 psia. It was shown that the RG 1.97 range requirements of 200°F subcooling and 35°F superheat are satisfied.

The monitoring system displays several levels of information including (1) bulk average core exit thermocouple trending, (2) a spatial map exhibiting the thermocouple temperature at its respective location in the core, (3) a core map showing minimum, average, and maximum quadrant temperatures, (4) subcooling margin, (5) a detailed data list exhibiting thermocouple location, tag designation, and temperature, and (6) hot channel core exit temperature.

The reactor vessel level instrumentation system (RVLIS) consists of two redundant, independent trains that monitor the reactor vessel water levels. Each train provides two vessel level indications: full range and dynamic head. The full-range RVLIS reading provides an indication of reactor vessel water level from the bottom of the vessel to the top of the vessel during natural circulation conditions. The dynamic head reading provides an indication of reactor core, internals, and outlet nozzle pressure drop for any combination of operating reactor coolant pumps. Comparison of the measured pressure drop with the normal, single-phase pressure drop provides an approximate indication of the relative void content of the circulating fluid.

Two analog indicators (per train) in the control room display the RVLIS readings, one for dynamic head and one for full range. The applicant stated that the cable routing from sensor input to display meets RG 1.75. The range of the full-range channels corresponds to 0% to 120% of the reactor vessel height. The inside bottom of the vessel to the inside top of the vessel head is approximately 41 ft. This is equivalent to 100% of the full-range level.

Evaluation and Conclusions

The staff has reviewed the applicant's submittal dated February 24, 1986, and its conclusions are:

(1) The commitment to complete installation and testing before fuel is loaded and calibration before the plant achieves 5% power is acceptable.

For new fuel the quantity of decay products in the core is extremely low; hence, the residual heat in the core following a shutdown is also low and easily removed. This lowers the risk of inadequate core cooling. Therefore, the health and safety of the public is not compromised as long as calibration is completed and the systems are fully operational before 5% power is exceeded.

(2) The implementation schedule for the ICC instrumentation system is not described. However, the staff will require that the ICC instrumentation system shall be fully operational with appropriate emergency operating procedures in place before fuel is loaded and that the system shall be fully calibrated before 5% power operation is exceeded. The acceptability of the final design will be demonstrated by the successful completion of preoperational testing of the ICC subsystems. An implementation letter report is required to complete the staff's review for implementation approval of the installed ICC system and must be provided before 5% power operation is exceeded. The implementation letter report should contain

  (a) notification that the system installation, functional testing, and calibration are complete and test results are available for inspection

  (b) summary of applicant conclusions based on test results, e.g.,

    - performance of the system in accordance with design expectations and within design error tolerances, or

    - description of deviations from design performance specifications and basis for concluding that the deviations are acceptable

  (c) description of any deviations of the as-built system from previous design descriptions with any appropriate explanation

  (d) confirmation that the emergency operating procedures (EOPs) used for operator training are complete and conform to the technical content of NRC-approved EOP guidelines (generic or plant specific)

(3) The core exit temperature monitors, subcooling margin monitors, and reactor vessel level monitors meet the single-failure criteria of RG 1.53. No single failure within the ICC instrumentation or its auxiliary support equipment will render the system inoperable.

(4) FSAR Section 7.5.4.4 states that ICC variables are all Category 1 and the ICC equipment is environmentally qualified in accordance with RG 1.89. The quality assurance of the ICC Category 1 instrumentation will be in accordance with the QA program described in FSAR Chapter 17. This is considered provisionally acceptable and may be confirmed by inspection at a future date.

On the basis of its review of FSAR Sections 4.4.6.5 and 7.5 and the additional information provided by the applicant, the staff finds that the design of the Seabrook Station ICC instrumentation system is in conformance with NUREG-0737, Item II.F.2, and is, therefore, acceptable.

### 4.4.8 Summary and Conclusions

In the SER, references to NUREG-0737, Item II.F.2, "Instrumentation for Detection of Inadequate Core Cooling," were made in this section. This subject matter is fully addressed in Section 4.4.5.4 of this supplement.

# 5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

## 5.2 Integrity of Reactor Coolant Pressure Boundary

### 5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

This section was prepared with the technical assistance of U.S. Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

#### 5.2.4.3 Evaluation of Compliance With 10 CFR 50.55a(g) for Seabrook Unit 1

This evaluation supplements conclusions in this section of the SER, which addresses the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Supplement No. 4 previously reported that the staff considered the review of the preservice inspection (PSI) program to be an open issue subject to the applicant (1) documenting the effectiveness of the ultrasonic testing procedures and instrumentation for examining the cast stainless steel weldments in the primary piping systems and (2) submitting all relief requests with supporting technical justifications.

The staff has completed its review of the FSAR through Amendment 58 dated April 1986; the "Seabrook Unit 1 Balance of Plant (BOP) PSI Program," Revision 1, dated January 6, 1984; the "Seabrook Unit 1 Reactor Pressure Vessel PSI Program Plan," Revision 3, dated March 15, 1984; the "Supplemental Examination Program Plan (SEPP) for Seabrook Unit 1," Revision 0, dated November 25, 1985; a letter from the applicant dated December 20, 1985, responding to the staff concerns in Supplement No. 3; the "Summary Report on Ultrasonic Examinations Performed at Seabrook Station Unit 1 on Statically Cast Fitting to Component Weldments," submitted May 15, 1986; and a submittal dated May 28, 1986, containing requests for relief from the ASME Code, Section XI requirements, which the applicant has determined are impractical for systems and components at Seabrook Unit 1.

On April 15, 1986, the staff met with the applicant at the Seabrook site for a specific demonstration to determine the effectiveness of the applicant's ultrasonic examinations on statically cast stainless steel using the qualified procedures on the Seabrook calibration blocks, mechanical fatigue crack specimens, thermal fatigue crack specimens, and actual plant welds. The applicant's examinations, using a 1-MHz, 1-in.-diameter dual-element transducer which produces a 41° nominal refracted longitudinal wave, were completed from the statically cast fitting side of the welds as the wrought side of the welds had been examined previously for PSI using conventional techniques. If indications were found, or significant attenuation changes noted, the 41° refracted longitudinal wave examination was then also completed from the wrought material side (pipe side) of the weld. All geometric indications of 50% distance amplitude correction or greater were recorded. Root geometry reflectors were verified by construction radiographs, and counterbore reflectors were verified using a longitudinal wave examination performed perpendicular to the pipe surface. On the basis of the discussions and demonstrations during the meeting at the plant site, the staff reached the following conclusions regarding the preservice ultrasonic examination of the cast stainless steel pipe welds:

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(1) The examination procedures meet the methodology requirements of Section XI of the ASME Code.

(2) The ultrasound was penetrating the region of the weld subject to examination and produced reflections from inherent geometrical conditions in the pipe that could be interpreted.

(3) The detection of significant construction-type defects, if present, was possible with the ultrasonic signal-to-noise ratios observed.

On May 15, 1986, the applicant submitted the "Summary Report on Ultrasonic Examinations Performed at Seabrook Station Unit 1 on Statically Cast Fitting to Component Weldments" for staff review. As a result of this review and the plant site demonstrations, the staff has determined that the fitting and piping welds in the primary coolant system at Seabrook Unit 1 have sufficiently good acoustical properties to permit a valid ultrasonic examination with state-of-the-art instrumentation. Therefore, the staff considers the issue of the preservice ultrasonic examination of welds in the primary coolant system resolved.

Requests for relief from the ASME Code, Section XI requirements, which the applicant has determined are not practical for systems and components within the reactor coolant pressure boundary, were submitted on May 28, 1986. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3); therefore, the staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and determined that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. On the basis of its review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that the PSI program for Seabrook Unit 1 is acceptable and the applicant has demonstrated compliance with 10 CFR 50.55a(a)(3). The detailed evaluation supporting this conclusion is provided in Appendix M to this supplement.

The initial inservice inspection program has not been submitted by the applicant. This program will be evaluated, as a condition to the license, on the basis of 10 CFR 50.55a(g)(4), which requires that the initial 120-month inspection interval shall comply with the requirements in the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months before the date of issuance of the operating license. This program will be evaluated after the applicable ASME Code edition and addenda can be determined and before the first refueling outage when inservice inspection commences.

## 5.4 Component and Subsystem Design

### 5.4.7 Residual Heat Removal System

#### 5.4.7.5 Tests, Operational Procedures, and Support Systems

In the staff SER, the staff stated: "The staff will require that the applicant provide a report justifying the applicability of the results of the boron mixing and natural circulation tests to be conducted at Diablo Canyon to the Seabrook design." The Diablo Canyon boron mixing and natural circulation test was conducted on March 28 and 29, 1985, at Unit 1, and is reported in Westinghouse Topical Reports WCAP-11086 (proprietary) and WCAP-11095 (nonproprietary). By letter dated June 1, 1986, the applicant submitted a report (YAEC 1552) describing the applicability of the Diablo Canyon Unit 1 natural circulation and boron mixing test to Seabrook.

Analyses of natural circulation in a pressurized-water reactor (PWR) and scaled experiments conducted under Electric Power Research Institute (EPRI) contract show that transient behavior in natural circulation is governed by heat transfer in the steam generator, while, for steady state, the important steady-state parameters (flowrate and core temperature difference) depend on flow resistance (EPRI Report NP-1363-SR). Diablo Canyon Unit 1 uses four 51 series steam generators, and Seabrook will use four model F steam generators. Although the designs are not identical, the steam generators have approximately the same heat-transfer-area-to-power ratios, and the elevations of the U tubes above the top of the fuel assemblies are approximately the same.

The differences in flow resistance in the reactor coolant systems (RCSs) of the two plant designs are not significant for this natural circulation capability comparison.

The applicant identified five areas in which a shutdown from full power and cooldown to cold shutdown would differ from the test performed at Diablo Canyon Unit 1. These are:

(1) method of RCS depressurization
(2) upper head temperature
(3) boron source
(4) residual heat removal initiation pressure
(5) reactor vessel internals

The staff has reviewed these differences between Diablo Canyon and Seabrook, which could be significant with respect to natural circulation cooldown, and finds that for these differences the comparisons are favorable. However, the staff is still reviewing the Diablo Canyon test report (WCAP-11086) and is also performing its own studies of what design and operation considerations should be considered in a comparison of the Diablo Canyon test to a given Westinghouse-designed PWR. Therefore, although the applicant has satisfied the staff requirement by providing a report describing the applicability of the Diablo Canyon Unit 1 test results to Seabrook, the staff considers this item to be confirmatory pending completion of the staff review of the Diablo Canyon test report (WCAP-11086).

Should any further questions arise as a result of the review of WCAP-11086 that are applicable to Seabrook, the applicant will be expected to provide the necessary responses. In a letter dated July 18, 1986, the applicant committed to provide any additional information that may be required in response to questions arising from the staff's further review.

Operation of Seabrook before the completion of the staff's review of WCAP-11086 is based on the following. The applicant has successfully performed a loss-of-offsite-power test during startup testing. Although this test does not demonstrate the ability to reach cold shutdown using only safety-related equipment, it does demonstrate that stable natural circulation cooling can be achieved. In addition, Westinghouse-designed reactors have successfully cooled down using natural circulation (Lanning and Wunderlick, 1984). Accordingly, the staff finds operation of Seabrook before completion of the staff's review of WCAP-11086 to be acceptable.

# 6 ENGINEERED SAFETY FEATURES

## 6.2 Containment Systems

### 6.2.1 Containment Functional Design

#### 6.2.1.1 Containment Analysis

In the SER, the staff reviewed and found acceptable the applicant's analysis of the peak containment atmosphere pressure and temperature that would occur during a loss-of-coolant accident (LOCA). By letter dated May 17, 1986, and by Amendment 58 to the FSAR, the applicant revised this analysis.

The principal changes were in the following initial conditions assumed as input to the analysis:

(1) Initial containment pressure was changed from 0.5 psig to 1.5 psig.

(2) Initial refueling water storage tank (RWST) temperature was changed from 86°F to 98°F; this resulted in a change in containment spray temperature during the injection phase from 88°F to 100°F.

The applicant's purpose in making these changes was to justify higher limits in the limiting conditions for operation in the Technical Specifications for these parameters (containment pressure and RWST temperature). This would provide greater operational flexibility for the plant.

As a result of this revised analysis, the calculated peak containment pressure increased from 46.1 psig to 49.6 psig. However, because the containment design pressure capability is 52.0 psig, this is acceptable.

Therefore, the staff finds the applicant's revised LOCA pressure and temperature analysis acceptable.

#### 6.2.1.2 Containment Subcompartment Analysis

The applicant has analyzed the pressure response of subcompartments inside the containment as a result of postulated high-energy line breaks. The mass and energy release data were input to the COMPRESS computer code to perform the subcompartment analyses.

Subcompartments in which high-energy line ruptures are postulated to occur include the reactor cavity, the steam generator compartments, the pressurizer compartment, and the pressurizer skirt cavity. A spectrum of breaks for each subcompartment is presented by the applicant in FSAR Table 6.2-16. The mass and energy release data for all postulated subcompartment breaks are listed in Tables 6.2-17, -24, -27, -30, and -33 of the FSAR.

In Supplement No. 4, the staff noted that it was continuing its evaluation of the applicant's subcompartment analysis and will report the results in a future

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supplement. The staff also noted that it needed the correct reference to the blowdown model used. The staff's review and evaluation of these matters are provided below.

The applicant states in the FSAR that the mass and energy release data for all high-energy line breaks considered for subcompartment analyses were generated by Westinghouse. However, the FSAR currently contains an incorrect reference to the blowdown model used. The applicant has agreed to include the appropriate reference (to Westinghouse Topical Report WCAP-8312-A) in a future FSAR amendment. This topical report was previously found acceptable by the staff (Vassallo, 1975). The staff, therefore, concludes that the methodology used in computing the mass and energy release data is acceptable.

The staff has reviewed the applicant's subcompartment calculations and the inputs made to them. The results show that the calculated differential pressures across the structural walls of the subcompartments are less than the corresponding design values. The staff finds this acceptable in accordance with the provisions of SRP Section 6.2.1.2.II.B.5.

The applicant has performed nodalization sensitivity studies for the subcompartments listed above. These studies showed that further subdividing of the nodes caused the pressure distribution on the structural walls to vary only slightly. Consequently, the staff concludes that the total load on the structural walls, resulting from pressurization of the subcompartments, was calculated in an acceptable manner. For the above reasons, the staff concludes that the noding models and calculated pressure transients are acceptable for use in the subcompartment structural analysis.

The applicant has also calculated the asymmetric blowdown pressure forces and moments acting on the reactor vessel, steam generator, and pressurizer. The nodalization sensitivity study discussed above also demonstrates the adequacy of these calculations.

The staff has reviewed the applicant's method of analysis, modeling assumptions, and results for the subcompartment analysis and finds them acceptable. The staff considers Confirmatory Issue No. 13 resolved.

### 6.2.4 Containment Isolation System

The SER states that the applicant committed to keep the 36-in. purge system isolated during all operating modes requiring containment integrity (power operation, startup, hot standby, and hot shutdown) and that the staff will include such a requirement in the plant Technical Specification (TSs). In this regard, TS 3.6.1.7 does require the 36-in. purge system to be isolated during operating modes requiring containment integrity.

The SER also states that the offsite radiological consequences of a loss-of-coolant accident during purging (using the 8-in. minipurge system) are addressed in Section 15 of the SER. By way of clarification, it is noted that this matter has been addressed in Section 6.2.4 of SER Supplement No. 4.

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## 6.2.6 Containment Leakage Testing Program

### Containment Air Lock Surveillance

By letter dated May 21, 1986, the applicant requested an exemption from certain requirements of Appendix J to 10 CFR 50.

Paragraph III.D.2(b)(ii) of Appendix J states: "Air locks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at not less than Pa."

Whenever the plant is in cold shutdown (mode 5) or refueling (mode 6), containment integrity is not required. However, if an air lock is opened during modes 5 and 6, Paragraph III.D.2(b)(ii) of Appendix J requires that an overall air lock leakage test at not less than Pa be conducted before plant heatup and startup (i.e., entering mode 4). The existing air lock doors are so designed that a full-pressure (i.e., Pa (49.6 psig)) test of an entire air lock can only be performed after strong backs (structural bracing) have been installed on the inner door. Strong backs are needed because the pressure exerted on the inner door during the test is in a direction opposite to that of the accident pressure direction. Installing strong backs, performing the test, and removing the strong backs requires several hours, during which access through the air lock is prohibited.

When no maintenance has been performed on the air lock that could affect its sealing capability, and the air lock doors have been closed in accordance with the applicant's procedure, and the periodic 6-month test at Pa required by Paragraph III.D.2(b)(i) of Appendix J has been performed on schedule, there is no reason to expect the air lock to leak excessively just because it has been opened in a shutdown or refueling mode. Performing the door seal leak test of Paragraph III.D.2.(b)(iii) of Appendix J is sufficient, in this case, to demonstrate the continuing integrity of the air lock.

Accordingly, the staff concludes that the applicant's proposed approach of substituting the seal leakage test of Paragraph III.D.2(b)(iii) for the full-pressure test of Paragraph III.D.2(b)(ii) of Appendix J is acceptable when no maintenance that could affect sealing capability has been performed on an air lock. Whenever maintenance that could affect sealing capability has been performed on an air lock, the requirements of Paragraph III.D.2(b)(ii) of Appendix J must still be met by the applicant.

The special circumstances for granting this exemption pursuant to 10 CFR 50.12 have also been identified. The purpose of Appendix J to 10 CFR 50 is to ensure that containment leaktight integrity can be verified periodically throughout service lifetime so as to maintain containment leakage within the limits specified in the facility Technical Specifications. The proposed alternative test method is sufficient to achieve this underlying purpose in that it provides adequate assurance of continued leaktight integrity of the air lock. In addition, at the time this section of Appendix J was revised in 1980, the staff did not contemplate the undue hardship and cost that would result from the requirement to perform a time-consuming full-pressure test before starting up from even the shortest cold shutdown during which the air lock had been used for containment entry. Because of this, the staff has already granted this same exemption to numerous plants and intends to revise Appendix J to alleviate the need for further similar exemptions. Consequently, the special circumstances described by 10 CFR 50.12(a)(2)(ii) and (iii) exist in that application of the regulation in these particular circumstances is not necessary to achieve the underlying purpose of the rule in that the applicant has proposed an acceptable alternative test method that accomplishes the intent of the regulation. Compliance would result in undue hardship that would be significantly in excess of that contemplated when the regulation was adopted and that would be significantly in excess of that incurred by others similarly situated in that plant startup would be delayed and unnecessary personnel radiation exposures would be incurred while an overall air lock leakage test was performed at full pressure.

Therefore, a partial exemption from this requirement (10 CFR 50, Appendix J, Paragraph III.D.2(b)(ii)) is justified and acceptable, and the applicant's proposal to adopt Surveillance Requirement 4.6.1.3 of Revision 4 of NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors," is acceptable (NUREG-0452, Rev. 4, was written to accommodate this type of exemption). Further, the staff finds that, in accordance with 10 CFR 50.12(a)(1), the requested partial exemption is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security, and that, in accordance with 10 CFR 50.12(a)(2)(ii) and (iii), special circumstances, as discussed above, are present.

### Type C Testing Program

The SER contains the staff's review and acceptance of the applicant's program for local leakage rate testing of containment isolation valves, designated as Type C testing in Appendix J to 10 CFR 50. However, the applicant has proposed, by letter dated May 7, 1986, to revise the Type C testing program. The following is a discussion of the penetrations and valves that will not be tested under the revised program; the remaining containment isolation valves will be Type C tested.

Containment penetrations X-1, X-2, X-3, X-4, X-5, X-6, X-7, X-8, X-48A, X-48B, X-49A, X-49B, X-63, X-64, X-65, and X-66 serve the main steam, feedwater, primary component cooling water, and steam generator blowdown systems. The applicant does not propose to Type C test the valves associated with these secondary system penetrations. This is not a change in the testing program; the original program contained the same provision, and was specifically reviewed and found acceptable by the staff in the Seabrook SER. The staff continues to find this acceptable. To briefly restate the basis for the SER conclusion: The secondary system is a closed system inside containment not postulated to rupture during an accident; it will preclude containment atmosphere from reaching the associated isolation valves, and, therefore, the valves will not be relied on to limit containment leakage. Although the primary component cooling water system is not part of the secondary system, it also forms a closed system inside containment and this argument applies equally to it. Therefore, the valves in these lines are not required to be Type C tested. The integrity of these closed systems inside containment will be tested during preoperational and periodic Type A (integrated leakage rate) testing.

Containment penetrations X-71A/74A, X-71B/74B, X-72A/75A, and X-72B/75B are the supply and return lines for the two hydrogen gas analyzers (CGC-CP-173 and CGC-CP-174). These lines form two closed systems (train A and train B) outside containment, which satisfy the following design criteria:

(1) The systems are seismic Category I.

(2) The systems are Safety Class 2 up to the analyzer isolation valves downstream of the containment isolation valves.

The isolation valves in these lines are expected to be open throughout an accident, and the closed systems outside containment will become extensions of the containment boundary. Standard Review Plan (SRP) Section 6.2.6, "Containment Leakage Testing," in Section II, states:

> Leak testing of instrumentation lines that penetrate containment may be done in conjunction with either the local leak rate tests or the containment integrated leak rate test [CILRT]. Instrumentation lines that are not locally leak tested should not be isolated from the containment atmosphere during the performance of the CILRT.

These isolation valves, therefore, will not be Type C tested. The integrity of the closed systems outside containment will be tested by opening the isolation valves during preoperational and periodic Type A (CILRT) testing, thereby subjecting each system boundary to postulated postaccident containment pressure. In accordance with SRP Section 6.2.6, the staff finds this acceptable.

Several containment penetrations associated with the emergency core cooling systems (ECCS) will have a water seal maintained at a pressure greater than 1.10 Pa following a loss-of-coolant accident. The ECCS satisfies the following design criteria:

(1) The system is Safety Class 2.

(2) The system is seismic Category I.

(3) The system is protected against missiles.

(4) The system is protected against the dynamic effects associated with pipe ruptures.

(5) Active electrical components are classified as 1E and receive emergency power from the diesel generators. Failure of a diesel generator results in the loss of one train of active ECCS components. The redundant diesel generator will continue to power the fully redundant ECCS train.

The penetrations at which this pressurized water seal will be maintained throughout the entire 30-day accident mitigation period are X-24, X-25, X-26, X-27, X-28, X-29, X-30, X-31, and X-33. In accordance with Paragraph III.C.3. of Appendix J to 10 CFR 50, these valves are not required to be Type C tested, because they are, in effect, sealed with water from seal systems with unlimited supplies of sealing water from the containment sump. Details of the hydraulic conditions at the penetrations and related system operation are described below.

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Some of the containment isolation valves involved are expected to remain open throughout the accident, in which case they would not be performing a containment isolation function and valve leakage would be irrelevant; however, if they were to close for any reason (e.g., valve failure), the pressurized water seal would be maintained and would prevent the valves from becoming potential containment atmosphere leak paths.

The postaccident operation of the ECCS can be described in three phases. Immediately following the accident, the residual heat removal (RHR) pumps, the centrifugal charging pumps, and the safety injection (SI) pumps are all aligned to take suction from the refueling water storage tank (RWST) and discharge to all four reactor coolant system (RCS) cold legs (cold leg injection). In the presence of the P signal (Phase B isolation), the containment spray (CS) pumps also take suction from the RWST and discharge to the spray ring headers. When the RWST reaches the low-low level, the containment sumps' isolation valves are manually opened and the system enters the cold leg recirculation mode. During this phase, the RHR pumps and containment spray pumps take suction from the containment sumps. The RHR pumps continue discharging to the RCS cold legs and also deliver water to a suction header common to the SI and charging pumps. These pumps also continue discharging to the RCS cold legs. Approximately 18 hours after the onset of an accident, the system is switched over to the hot leg recirculation mode. During this phase, the RHR and containment spray pumps continue taking suction from the containment sumps. The RHR pumps are aligned to discharge to RCS hot legs 1 and 4, as well as the SI/CS pumps' common suction header. The SI pumps are aligned to discharge to all four RCS hot legs, and the charging pumps continue discharging to all four RCS cold legs.

Penetration X-24 is the common discharge line from the centrifugal charging pumps to all four RCS cold legs. The isolation valves outside containment for the penetration (SI-V138 and SI-V139) will be open for the entire accident mitigation process. Both charging pumps discharge to a common header throughout accident mitigation. Therefore, a water seal at a pressure greater than 1.10 Pa will be maintained at the penetration for 30 days following the onset of an accident regardless of single active failure.

Penetrations X-25 and X-26 are the discharge lines from the SI pumps to all four RCS hot legs. The isolation valves outside containment for these penetrations (SI-V77 and SI-V102) will be closed for cold leg injection and cold leg recirculation and open during hot leg recirculation. During cold leg injection and recirculation, the crosstie line between both pumps' discharge lines will not be isolated. Therefore, regardless of single active failure, a water seal at a pressure greater than 1.10 Pa will still be maintained at these penetrations by the redundant SI pump. During hot leg recirculation, the crosstie isolation valves (SI-V111 and SI-V112) are closed. However, during both recirculation phases the RHR pump(s) deliver water to a suction header common to both SI pumps. During preoperational testing with one RHR pump delivering to this suction header, the suction pressure for both SI pumps was in excess of 1.10 Pa. Therefore, should a single active failure occur, a water seal pressurized to 1.10 Pa will still be maintained at the penetration corresponding to the failed SI pump by the lone operating RHR pump. It follows that a pressurized water seal will be maintained at these penetrations for 30 days following the onset of an accident regardless of single active failure.

Penetration X-27 is the discharge line to all four RCS cold legs from the SI pumps. The isolation valve outside containment for this penetration (SI-V114) will be open during cold leg injection and cold leg recirculation and closed during hot leg recirculation. This line is a continuation of the crosstie line between both pumps' discharge lines. Given the above discussion on penetrations X-25 and X-26, it follows that a pressurized water seal will be maintained at penetration X-27 for 30 days following the onset of an accident regardless of single active failure.

Penetrations X-28, X-29, X-30, and X-31 are the centrifugal charging pumps' discharge lines to the reactor coolant pumps' seals. The isolation valves outside containment for these penetrations (CS-V154, CS-V158, CS-V162, and CS-V166) do not close automatically following an accident and may remain open during accident mitigation. These lines are supplied with water from the discharge header common to both charging pumps. Therefore, a water seal at a pressure greater than 1.10 Pa will be maintained at these penetrations for 30 days following the onset of an accident regardless of single active failure.

Penetration X-33 is the normal charging line from the centrifugal charging pumps' common discharge header. The isolation valve outside containment for this penetration (CS-V143) will be closed throughout the entire accident mitigation process. Because the line is pressurized by the discharge header common to both charging pumps, the penetration will realize a water seal at a pressure greater than 1.10 Pa for 30 days following an accident regardless of single active failure.

As previously discussed, a water seal at a pressure greater than 1.10 Pa will be maintained at penetrations X-24, X-25, X-26, X-27, X-28, X-29, X-30, X-31, and X-33 for 30 days following the onset of an accident. This seal precludes any isolation valve seat leakage of containment atmosphere. In addition, all containment isolation valves for these penetrations located outside containment that may be closed at some time following an accident are wedge-type gate valves. The applicant states that their design allows for stem/packing leakage only from the high-pressure side of the wedge. Given that a water seal will be maintained on the side of the wedge gate away from containment at a pressure greater than 1.10 Pa, containment atmosphere leakage from the stems or packing on these valves would therefore be precluded. Therefore, the containment isolation valves associated with the penetrations listed above are not potential containment atmosphere leak paths. In accordance with Paragraph III.C.3. of Appendix J, these valves are not subject to Type C testing.

Containment penetrations X-60 and X-61 are the suction lines for the containment spray and RHR pumps from the containment sumps. Each of these penetrations has one isolation valve located outside containment (CBS-V8 and CBS-V14) which is normally closed and will remain closed during cold leg injection and will be open during cold and hot leg recirculation. The containment recirculation sumps and these associated penetrations will fill with water almost immediately following the onset of an accident and will remain filled with water for at least 30 days following the onset of an accident. These valves, therefore, do not constitute potential containment atmosphere leak paths, and as such are not required by Paragraph III.A.1.(d) of Appendix J to be Type C tested. Paragraph II.H. of Appendix J also defines four categories of valves that require Type C testing; they are those that

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(1) provide a direct connection between the atmosphere inside and outside containment under normal operation

(2) are required to close automatically upon receipt of a containment isolation signal

(3) are required to operate intermittently under postaccident conditions

(4) are in main steam and feedwater piping of boiling-water reactors

The valves in question are opened, rather than closed, and remain open for the duration of the accident. Thus, Paragraph II.H. does not require them to be tested. The staff concludes, therefore, that the valves in penetrations X-60 and X-61 are not subject to Type C testing.

In conclusion, the staff finds, on the basis of the above evaluation, that the applicant's proposed Type C testing program, as described in the letter dated May 7, 1986, complies with the requirements of Appendix J to 10 CFR 50 and is acceptable.

### 6.2.8 TMI Action Plan Requirements

#### II.E.4.2 Containment Isolation Dependability

Item II.E.4.2 of NUREG-0737 states that fluid lines of nonessential systems that penetrate containment should be automatically isolated in response to the containment isolation signal. In FSAR Amendment 56, the applicant defined an essential system (or line) as one that is necessary for mitigating the consequences of an accident and identified the essential systems and lines in FSAR Table 6.2-83. They include the residual heat removal system, containment spray system, high head safety injection system, and containment pressure-sensing lines. All other fluid lines penetrating containment are identified in Table 6.2-83 as being nonessential. The staff noted, however, in Section 6.2.8 of Supplement No. 4, that the following nonessential system lines were not automatically isolated:

(1) chemical and volume control reactor coolant pump seal injection (penetrations 28, 29, 30, and 31)

(2) primary component cooling water thermal barrier (penetrations 48A, 48B, 49A, and 49B)

(3) reactor coolant system (penetrations 77A, 77B, 78A, and 78B)

By letter dated May 7, 1986, the applicant provided additional information justifying the isolation provisions for these lines.

Penetrations 28, 29, 30, and 31 are the centrifugal charging pump discharge lines of the chemical and volume control system that supply injection water to the reactor coolant pump (RCP) seals. Although these lines are not essential for accident mitigation, it is desirable to continue cooling water to the RCPs for as long as possible under transient and accident conditions.

The containment isolation provisions for these lines consist of check valves inside containment and remote manual, motor-operated valves outside containment. This deviates from the explicit requirements of GDC 55 to the extent that the valves outside containment are not automatic isolation valves. With these lines in service, postaccident high pressure water is flowing into containment, which precludes their becoming containment atmosphere leak paths.

Remote manual isolation of the outboard containment isolation valves is justified on the grounds that the closed, safety-grade system (i.e., the emergency core cooling system), to which these lines attach, provides a reliable backup isolation barrier against containment atmosphere leakage. Thus, on this other defined basis, the isolation provisions for these lines satisfy the requirements of GDC 55.

Penetrations 48A, 48B, 49A, and 49B are the primary component cooling water (PCCW) system supply and return lines for two heat exchangers located inside containment; each line has one remote manual, motor-operated isolation valve outside containment. The two heat exchangers remove heat from the thermal barrier loop, which circulates cooling water to the RCP thermal barrier cooling coils.

Depending on the postaccident operating requirements of the RCPs, continued operation of the PCCW system may be necessary following an accident; as a result, the lines are not automatically isolated.

The PCCW system is a safety-grade, closed system inside containment and does not communicate with either the reactor coolant system or the containment atmosphere. Furthermore, the system is located outside the missile barrier. The system design and isolation valve provisions satisfy the requirements of GDC 57. Therefore, the staff finds acceptable the applicant's plans for delaying isolation of these lines.

Penetrations 77A, 77B, 78A, and 78B serve the reactor vessel level indication system, which provides information necessary for accident mitigation. The applicant has reclassified the system as essential and has committed to revise the FSAR to reflect this change. The staff finds the applicant's approach acceptable.

The SER found it acceptable for the minipurge (i.e., 8-in. purge) system to be open up to 1000 hours per year during plant operating modes 1 through 4 (i.e., power operation, startup, hot standby, and hot shutdown). However, the staff conditioned its acceptance on the finding that (1) the isolation valves will remain operable under the dynamic conditions of a loss-of-coolant accident (see SER Section 6.2.4) and (2) there is a justifiable need for the minipurge system to be opened and its cumulative use is known (see SER Sections 6.2.4 and 6.2.8).

With respect to Item (1), the operability of the minipurge system containment isolation valves is discussed in Section 3.10.3 of this supplement. With respect to Item (2), the staff has discussed with the applicant the expected need for containment purging, and the resolution of this matter is discussed below.

TS 3.6.1.7 will no longer prescribe an allowable annual number of hours of purge system use on the basis of the findings of a staff analysis in NUREG-0933.

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This analysis showed that the maximum public risk reduction that an average operating plant could realize by completely prohibiting purge system use would be extremely low. Therefore, because the applicant has committed to use the 8-in. minipurge system exclusively during operating modes 1 through 4 for safety-related reasons only, and the reasons are delineated in TS 3.6.1.7, the staff has concluded there is no need to impose further limitations on purge system operation. Furthermore, the applicant has committed, through TS 4.6.1.7.4, to verify every 31 days that the minipurge system is being used in accordance with TS 3.6.1.7. In TS 4.6.1.7.2 and TS 4.6.1.7.3, the applicant has also prescribed the surveillance requirements for monitoring the leakage integrity of the containment isolation valves in the 36-in. and 8-in. purge systems, respectively. On this basis, the staff finds acceptable the applicant's proposed containment purging practices as delineated in the Technical Specifications noted above.

The SER states that the applicant committed to verify the closure of the 36-in. purge system isolation valves every 31 days. The staff notes that this surveillance practice has been incorporated in TS 4.6.1.7.1.

## 6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

### 6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g) for Seabrook Unit 1

This evaluation supplements the conclusions in this section of the SER, which addresses the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Supplement No. 4 previously reported that the staff considered the review of the preservice inspection (PSI) program to be an open issue subject to the applicant submitting all relief requests with supporting technical justification.

The staff has completed its review of the FSAR through Amendment 58 dated April 1986; the "Seabrook Unit 1 Balance of Plant (BOP) PSI Program," Revision 1, dated January 6, 1984; the "Supplemental Examination Program Plan (SEPP) for Seabrook Unit 1," Revision 0, dated November 25, 1985; a letter from the applicant dated December 20, 1985, responding to the staff concerns in Supplement No. 3; and a submittal dated May 28, 1986, containing requests for relief from the ASME Code, Section XI requirements, which the applicant has determined are not practical for systems and components at Seabrook Unit 1.

Requests for relief from the ASME Code, Section XI requirements, which the applicant has determined are not practical for Class 2 and Class 3 components were submitted on May 28, 1986. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluated the ASME Code-required examinations that the applicant determined are impractical and determined that the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. On the basis of its review of the applicant's submittals and the granting of relief from these preservice examination requirements, the staff concludes that the PSI program for Seabrook Unit 1 is acceptable and in compliance with

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10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix M to this supplement.

The initial inservice inspection program has not been submitted by the applicant. This program will be evaluated, as a condition to the license, on the basis of 10 CFR 50.55a(g)(4), which requires that the initial 120-month inspection interval shall comply with the requirements in the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months before the date of issuance of the operating license. This program will be evaluated after the applicable ASME Code edition and addenda can be determined and before the first refueling outage when inservice inspection commences.

# 7 INSTRUMENTATION AND CONTROLS

## 7.2 Reactor Trip System

### 7.2.2 Specific Findings

### 7.2.2.4 Turbine Trip on Reactor Trip

As discussed in Section 7.2.2.4 of the SER, the applicant committed to install for turbine trip circuitry requirements redundant, safety-related circuits and solenoids powered from Class 1E inverters. Subsequently, the applicant modified the original design proposal and, on a request from the staff, provided information by letters dated February 14, 1986, and May 10, 1986, to describe the latest turbine trip on reactor trip system.

The turbine trip circuit design complies to the maximum extent practicable with the applicable requirements of IEEE Standard 279 (Sections 4.2, 4.3, 4.5, 4.6, and 4.10 specifically) with the exception of seismic qualification. Redundant, Class 1E P-4 (reactor trip breakers open) signal inputs are provided to the two turbine trip circuits. Discussions with the applicant have revealed that the input signal circuitry routed through the nonseismic structure is isolated, so the protection system performance is not degraded below an acceptable level. One trip circuit energizes the mechanical trip solenoid, while the other deenergizes the electrical trip solenoid to depressurize the emergency trip system and to close the turbine valves. Cross-trip circuits are provided so that either of the redundant (P-4 train A or train B) trip signals will activate both turbine trip circuits. The entire turbine control system is considered A-associated. Thus, a qualified isolation relay is provided to change the train B reactor trip input signal from B-associated to A-associated for input to the turbine control system. On the basis of the information above, the staff considers this design consistent with the importance to safety of the function and, therefore, acceptable.

## 7.3 Engineered Safety Features System

### 7.3.2 Specific Findings

### 7.3.2.4 Indicator, Alarm, and Test Features Provided for Instrumentation Used for Safety Functions

In the SER, the staff stated that each safety function can be tested without lifting leads or the use of jury rigs. Subsequent to this SER input (November 1985 meeting), the staff was informed of the need for temporary circuit modifications during various instrumentation surveillance tests. Details have been provided by letters dated April 7, 1986, and June 5, 1986. The staff's evaluation of this information is provided in Section 7.3.2.14 of this supplement.

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### 7.3.2.8 Level Measurement Errors as a Result of Environmental Temperature Effects on Level Instrument Reference Legs

The SER stated that the applicant was requested to describe how the effects of high temperatures on reference legs of steam generator and pressurizer water level measuring instruments after high-energy line breaks are evaluated and included in the Seabrook design. This issue was addressed for operating reactors in NRC Office of Inspection and Enforcement (IE) Bulletin 79-21. The SER also stated that the applicant responded that the evaluation of transient heating of reference legs had not yet been completed and that the applicant agreed to provide additional information on steam generator and pressurizer level reference leg heating. As a result, this concern was made an open item pending receipt and review of additional formal documentation.

By letter dated April 15, 1986, the applicant provided analyses regarding the effects of high temperatures in level reference legs of the steam generator and pressurizer. These analyses discussed the following residual effects of postaccident conditions on indicated level: (1) reference leg heatup, (2) reference leg boiling, and (3) process density changes. These effects were then postulated to occur, and their results on safety-related level setpoints were analyzed as follows.

#### Steam Generator Low-Low Level Reactor Trip and Emergency Feedwater Initiation

The applicant performed analyses to determine the maximum level error resulting from reference leg heatup using the following considerations and/or assumptions:

(1) Containment response was analyzed with the CONTRAST-S (United Engineers and Constructors, Inc., June 1979) computer program using passive heat sink data given in FSAR Tables 6.2-3 and 6.2-4. Conservatively high heat transfer coefficients have been used for the passive heat sinks to delay the containment pressure rise.

(2) Breaks are double ended, and the break effluents from both sides do not interfere with each other. This conservatively envelopes all types of breaks and maximizes containment temperature by maximizing the steam enthalpy.

(3) The mass and energy release rates are calculated assuming choked flow through the break.

(4) Initial containment conditions are 14.7 psia, 120°F, and 100% relative humidity.

(5) Hi-1 trip operates before 5.8 psig (20.5 psia) is reached, which includes an allowance for instrumentation uncertainties. All functions actuated by the Hi-1 trip occur.

(6) Pressure buildup is delayed and air is purged from the containment by venting through the containment on-line purge system. A discharge coefficient of 1.0 is used. The pressure downstream of the purge valve is conservatively assumed to be 13.5 psia.

(7) Containment free volume is 2.84 x $10^6$ $ft^3$ (approximately 5% higher than that used in the design-basis-accident analysis).

(8) The reference leg response is calculated following guidelines in NUREG-0588 using the HESITET (United Engineers and Constructors, Inc., October 1979) program.

(9) Containment high-pressure alarm is actuated at 15.7 psia (1.0 psig).

(10) All events that reach the Hi-1 setpoint 15 min or more after the high-pressure alarm are manually terminated within 15 min of the alarm.

The results of these analyses show that the critical break size has an area of approximately 0.031 $ft^2$. The maximum reference leg water temperature is 180°F at 970 sec after the break. The high-pressure alarm is actuated at 70 sec. The applicant determined that if the high-pressure alarm increased by 2.0 psig, the maximum temperature would be 185°F. The increase in reference leg water temperature to 185°F results in an error of 3.1%. This reference leg error has been included in the calculated value for the low-low level trip setpoint of 17.1%.

The most accurate alarm for alerting the operators to abnormal conditions within the containment is the high containment pressure alarm at 15.7 psia. Input to the alarm is provided by COP-PT-1787, which has a range of 12 to 18 psia. Normal containment pressure is 15.2 psia with a Technical Specification limit of 16.2 psia. The applicant has accounted for this higher setpoint allowance in the analyses.

Other alarms that are currently available to alert the operator to abnormal conditions inside the containment resulting from a small feedwater line break are

(1) containment leakage monitoring
(2) feed/steam mismatch
(3) steam generator level deviation (set at programmed level ±5%)
(4) steam generator low-level (set at 30%)

The steam generator level deviation alarm is provided on both the annunciator and the video alarm system (VAS). The other alarms are provided on the VAS. Failure of the VAS actuates an alarm on the annunciator.

The applicant committed to increase the reliability of the appropriate alarms by implementing the following changes before core load:

(1) Provide diverse alarms from COP-PT-1787 by adding an annunciator alarm from bistable COP-PDW-1787 and generating a VAS alarm from the analog input (A3250).

(2) Generate a high containment pressure alarm (about 2.0 psig) from SI-PT-936 analog input (A0502). The alarm will be set as low as is feasible without causing nuisance alarms (channel has a span of 0 to 60 psig).

## Steam Generator High-High Level Trip

The steam generator high-high level trip provides protection for excess feedwater flow events. These events do not cause a harsh environment; therefore, the trip setpoint will not be changed.

## Pressurizer High-High Level Trip

The pressurizer high-high level trip provides protection for an increase in reactor coolant inventory events. These events do not cause a harsh environment before actuation of the trip; therefore, the trip setpoints will not be changed.

The emergency operating procedures at Seabrook will follow the Westinghouse Owners Group Emergency Response Guidelines. These guidelines specifically require that the instrumentation errors due to environmental effects and system pressure changes be considered. The applicant has performed appropriate error calculations and incorporated them in the emergency operating procedures.

The staff was concerned regarding the credit that was taken by the applicant for the limited operator action based on receipt of a non-safety-related high-pressure alarm and high containment pressure indication. In addition, the staff was concerned that the FSAR analyses may not be bounding when containment considerations and the effect on indicated steam generator (SG) levels are considered.

The FSAR analyses pertinent to a feedwater line break were conducted without consideration of interaction with the containment. As a result, no credit was taken for reactor trip due to a Hi-1 containment signal, nor was credit taken for operator mitigation of the accident on the basis of the containment condition. Reactor trip was assumed to occur on the basis of the SG low-low level trip, which was assumed to occur at zero level on the narrow-range indicator.

The FSAR analyses further were restricted to large, offset, double-ended breaks. This was justified on the basis of parametric variation of break-size analyses, which established that the large break represented the worst condition. These analyses were reported in Westinghouse Topical Report WCAP-9230, which was provided to the staff in 1978. Note that the previously discussed analyses pertinent to containment interaction with the SG level instrumentation established that the worst condition was a small break, since large feedline breaks would result in a Hi-1 trip early in the accident.

The staff has reviewed the applicant submittals pertinent to containment interaction (applicant reports SBN-955 (February 28, 1986), SBN-1004 (April 15, 1986), and SBN-1085 (June 3, 1986)), as summarized above. The staff has reviewed the FSAR as applicable to this issue and has studied WCAP-9230. These efforts have led to the following staff conclusions:

(1) The assumptions pertinent to containment response and interaction analyses lead to a conservative evaluation of containment temperature as it affects SG liquid level indication.

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(2) Operator actions, as described in the applicant submittals and which occur within 15 min of reaching a containment high-pressure alarm, in conjunction with a containment Hi-1 trip signal, are sufficient to ensure a reactor trip so that the consequences are no worse than would occur if there were no error in the SG level indication, and the trip occurred at a narrow range level of zero.

(3) Since reactor trip will limit the consequences to no worse than those reported in the FSAR or in WCAP-9230, the consequences of feedwater line breaks will be no greater than those reported in those documents.

(4) Since the consequences as reported in the FSAR bound the consequences as reported in WCAP-9230, the FSAR reported analyses are bounding.

(5) The staff finds the applicant submittals pertinent to containment interaction, including the effect of containment conditions on SG level indications, acceptable. The staff further finds that the FSAR analyses are conservative with respect to consideration of containment conditions.

By letter dated June 3, 1986, the applicant committed to provide high containment pressure alarms and containment pressure indication, which meet the criteria in FSAR Section 7.5.4.4 for Design Category 1 accident monitoring instrumentation, before 5% power is exceeded. The applicant has stated that the containment pressure indicator will be a narrow-range indicator to allow the operator to check easily for a containment pressure increase. In addition, the applicant will ensure that the added alarms receive adequate prioritization relative to other events that may be taking place in the control room during a high-energy line break. Since the Category 1 instrumentation as discussed above will not be installed until 5% power level is exceeded, the applicant has committed to keep the containment purge valves closed when in mode 2 under the low-power license.

The staff has reviewed the applicant's analyses of the effects of high temperatures in reference legs of water level measuring instruments, including the basis and assumptions used to establish the error allowance that is included in the low-low steam generator level setpoint and the associated hardware changes as denoted above. The applicant's submittals provide reasonable assurance that the level indication error will remain within the stated bounds, irrespective of break size, before a containment Hi-1 trip, provided the containment purge valves are closed. Thus, trip on low-low SG level or containment Hi-1, whichever occurs first, will preclude a condition worse than that previously analyzed in the FSAR or WCAP-9230. Therefore, the staff finds this mode of operation acceptable and Outstanding Issue No. 10, "Level Measurement Errors," is resolved.

### 7.3.2.11 Emergency Feedwater System

The SER stated that the applicant should formally revise the FSAR and appropriate drawings to describe the final emergency feedwater system (EFWS) design. The applicant has provided FSAR information (through Amendment 56) that confirms the EFWS design as described in SER Section 7.3.1.7. By letter dated February 14, 1986, the applicant has provided reference to the instrumentation and control drawings that reflect the latest EFWS design. On the basis of its review of this information, the staff considers this issue resolved.

### 7.3.2.14 Conformance to RG 1.118 and IEEE 338

As stated in the SER, the applicant committed to notify the staff promptly if temporary modifications were found to be necessary during periodic testing of protection systems. During a November 1985 meeting, the staff was informed of the need for temporary circuit modifications. When asked for details, the applicant provided information by letters dated April 7, 1986, and June 5, 1986.

The information provided identifies (by procedure number and title) where a given surveillance test condition requires temporary circuit modifications (lifted leads, jumpers, removal of fuses, and test adapters). The applicant has reviewed all test procedures to reduce the requirement for the use of modifications where possible. The modifications make use of designed test points, test jacks, and hardware connection points. The applicant has confirmed that the instrumentation and control (I&C) test procedures have a point-by-point verification on the return-to-normal-status condition. The I&C procedures require second-person verification through signoff by that individual. The second person cannot be directly involved in the actual movement or relocation of equipment but shall be knowledgeable about the equipment undergoing surveillance testing. An additional independent verification is performed to ensure that the equipment is returned to its normal service condition.

On the basis of its review, the staff finds that the combination of explicit testing procedures and administrative controls (independent second-person verification) meets the guidelines of IE Information Notice 84-37, "Use of Lifted Leads and Jumpers During Maintenance and Surveillance Testing," and, thus, provides reasonable assurance that the instrumentation will be restored to the correct configuration following testing where temporary modifications are required. Therefore, the staff considers this issue resolved.

### 7.3.2.15 Conformance to RG 1.75

As reflected in the SER, the staff concluded that the Seabrook design adequately conformed to the provisions of RG 1.75, Revision 2, and IEEE Standard 384. As required in the SER, the applicant has provided formal documentation by a January 25, 1983, letter to support the staff's conclusion. However, subsequent to the issuance of the January 25, 1983, letter, the staff was informed of an area of nonconformance with the required separation criteria during the review of information related to possible interconnections between electrical divisions as discussed in SER Section 8.3.1.8.

The staff learned that train A-associated and train B-associated circuits interface (lack required separation) with each other within various cabinets utilized to process and transmit certain field inputs for use by the main plant computer. These cabinets are identified as intelligent remote terminal units (IRTUs). The applicant has performed an analysis to show that the subject interface will not cause detrimental interaction between the redundant separation groups which provide input to the IRTUs. Also, upon request, the applicant has performed tests to support the analysis. The analysis and test results have been reviewed and found acceptable by the staff as reported in Section 8.3.1.8 of this supplement. Therefore, the staff considers this item resolved.

## 7.4 Systems Required for Safe Shutdown

### 7.4.2 Specific Findings

#### 7.4.2.1 Station Service Water System

As discussed in the SER, the secondary (nonseismic portion) component cooling water heat exchangers are automatically isolated from the safety-related service water system piping on a loss of offsite power, tower actuation (TA) signal (low service water pump discharge pressure), or a safety injection signal. The staff expressed a concern that if there is an earthquake without an accident or loss of offsite power, the nonseismic piping can be assumed to fail, and the nonseismic portion of the service water system may not receive an automatic signal to isolate as required. The applicant has provided additional information to address this issue by letters dated February 14, 1986, and May 10, 1986.

It has been determined from analyses performed by the applicant that any nonseismic pipe failure greater than 8 in. will result in a TA signal. The remaining concern relates to the effect of reduced flow to the safety equipment for failures of the non-safety-related piping that do not cause a TA. The applicant subsequently analyzed the effect of the largest non-safety-related piping failure (8 in.) that does not result in a TA taking into consideration worst-case conditions (maximum normal operation water temperatures and heat loads, etc.). The applicant has concluded from its analyses that any failure of the nonseismic piping will not prevent the accomplishment of the safety functions should they be required.

The staff challenged the worst-case temperature conditions that might exist as related to use of the cooling towers during normal plant operation for heat treatment of the normal service water tunnels in combination with diesel generator full-load testing. The applicant responded stating that a Technical Specification limiting condition exists for operation of the cooling tower during normal plant operation to maintain the basin temperature below a specific temperature (67.3°F). As long as the basin temperature is at or below 67.3°F, the applicant has confirmed that failure of the nonseismic piping will not result in unacceptable consequences. The applicant has committed to include (before core load) in the procedures for cooling tower operation during normal power operation restrictions on operation of the diesel generators when the Technical Specification basin temperature could be exceeded. The staff will verify such procedures are in place before core load.

On the basis of the above discussion and subject to satisfactory verification by the staff of implementation of procedural restrictions on diesel generator operation during normal plant operation, the staff considers this acceptable.

#### 7.4.2.2 Main Steam Atmospheric Relief Valves

The SER indicates that the Seabrook design will include safety-related electrohydraulic actuators for the atmospheric steam dump valves (ASDVs) that would be powered from the emergency power sources. Subsequently, the applicant informed the staff in a November 1985 meeting (with followup letters dated February 14, 1986, and May 10, 1986) that, instead of the original proposed electrohydraulic actuator design, the ASDVs will be air operated. The actuators will be provided with safety-related controls and backup air supplies (nitrogen-backed bottles).

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The actuators (including air supply) and manual control circuits will comply with the seismic and environmental requirements. The applicant has provided information to verify that the safety-related air system has sufficient capacity to operate the ASDVs for 10 hours and that this will provide adequate time to cooldown from hot standby to residual heat removal system operation. Seismically qualified transmitters will be installed to provide control room pressure indication and an alarm for each set of gas bottles.

The staff has reviewed drawings to confirm the safety-related control portion of the design, which included verification that the manual control circuitry will be Class 1E with power to be supplied from the emergency power sources. Safety-related manual control will exist at both the main control board and remote shutdown panels. The applicant has provided information to confirm that with any postulated single failure, there will always be at least two ASDVs available for safe plant shutdown. Also, the manual control circuitry will override (isolate when required) the non-safety-related automatic controls that are associated with the plant normal instrument air system.

On the basis of its review of these latest modifications, the staff considers this issue resolved. Periodic testing and surveillance requirements shall be included as part of the Technical Specifications to check the operability of the ASDVs and associated manual controls including the safety-related gas supply system.

### 7.4.2.3 Instrument Air System

As required by the SER, the applicant has provided formal information (letters dated February 14, 1986, and May 10, 1986, and FSAR information through Amendment 56) to confirm that safe plant shutdown can be accomplished without the use of the non-safety-related instrument air system. The applicant has verified that (1) the emergency feedwater flow control valves will not utilize pneumatic operators (will be motor-operated valves), (2) the atmospheric dump valves will be provided with a backup safety-related air supply system (nitrogen-backed bottles) as described in Section 7.4.2.4 of this supplement, and (3) the residual heat removal system can be operated without the use of instrument air.

On the basis of its review of the additional information as described above, the staff considers this issue resolved.

### 7.4.2.4 Remote Shutdown From Outside the Control Room

As stated in the SER, the applicant committed to modify FSAR Section 7.4 to reflect the latest design and to address staff guidance regarding the remote safe shutdown equipment/systems. The applicant has provided additional information by amending the FSAR (Amendment 56) and through letters dated May 10, 1986, and June 5, 1986.

If the control room should become uninhabitable, the plant can be brought to and maintained in a hot standby condition and then subsequent cold shutdown mode using alternative control provisions located outside the main control room at various remote safe shutdown (RSS) locations. The RSS locations utilized for achieving and maintaining hot standby are the vital switchgear rooms, which are two levels directly below the control room. Access is through the stairwell on the south side of the control building or through stairwells in the turbine building. Access to all levels of the control building is controlled by the station security system. The operators' key cards will allow access to all levels of the control building. Administratively controlled keys are also available to ensure access should the security system become inoperable.

Before evacuating the control room, the operator will trip the reactor, close the main steam isolation valves, and trip the reactor coolant pumps. The capability exists outside the main control room to accomplish these functions should it be necessary. Redundant, safety-related controls required for safe shutdown are located at the RSS locations. The controls comply with the applicable requirements of IEEE Standard 279, including seismic and environmental qualification. The control provisions at the RSS locations consist of selector switches that isolate the main control room on transfer of control to the local station. Jumpers, lifted leads, or temporary circuits are not required. Selecting local control for any component initiates an alarm in the main control room.

Indication instrumentation at the remote shutdown locations required for safe plant shutdown (with the exception of wide-range nuclear instrumentation) consists of separate loops that are completely independent of the instrument loops that provide indication in the control room. The applicant has provided information to certify that the instrumentation circuits including transmitters and indicators will be operable following all natural phenomena including seismic events. This information was audited during the Seabrook site visit the week of May 12, 1986. The wide-range nuclear instrumentation including indicators will be safety related.

During the review process, the staff challenged the portion of remote safe shutdown procedures whereby the operator is instructed to disable the solid state protection system (SSPS) (train A and train B). The applicant responded with information to justify such planned procedures. The operator will obtain a stable (hot standby) condition from outside the control room from the RSS locations. After cooldown has commenced from the stable condition, the operators will go to power panels 1A and 1B (located in the switchgear rooms with the remote shutdown panels) and open breaker number 11 in each panel to disable trains A and B of the SSPS. These panels are in close proximity to the other remote shutdown controls (location was verified during the NRC site visit the week of May 12, 1986). The applicant reviewed the list of equipment affected by the SSPS disabling function and concluded that such an operation will not negate any functions required for remote safe shutdown. The SSPS can be reestablished, if necessary, during the plant cooldown by reclosing the appropriate breakers. The applicant has determined that possible reestablishment of the SSPS during plant cooldown will not result in unsatisfactory consequences related to remote safe plant shutdown.

On the basis of the above discussion, the staff considers the remote safe shutdown issue resolved.

### 7.4.2.5 Pressurizer Auxiliary Spray

The SER stated that the applicant should provide formal documentation related to the use of pressurizer power-operated relief valves (PORVs) for safe shutdown. By letter dated February 14, 1986, and through FSAR Amendment 56, the

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applicant has provided information that verifies that redundant safety-related pressurizer PORVs are to be used to depressurize the reactor coolant system during safe plant shutdown instead of the pressurizer auxiliary spray valves. The information also confirms that the PORVs and associated block valves can be controlled manually from either the control room or remote shutdown panels. On the basis of this latest information, the staff considers this issue resolved.

## 7.5 Information Systems Important to Safety

### 7.5.2 Specific Findings

### 7.5.2.2 Radiation Data Management System

The SER stated that the overall design concept and use of the radiation data management system (RDMS) are acceptable to the staff. However, the SER further stated that two specific features of the RDMS require staff review. These features are (1) qualification testing of the RDMS isolation devices and (2) the software verification and validation (V&V) program. The following provides additional safety evaluation input related to the RDMS design and its associated issues.

### Isolation Devices

The Seabrook RDMS is an integrated computer-based system used for controlling and simulating data from plant radiation monitors. A portion of the RDMS is safety related (various radiation monitors and their associated microprocessor computers are designated as Class 1E). The Class 1E monitors (RM 80s) interface with the RDMS host computer (RM 11) or with other redundant safety-related microprocessors (opposite electrical division) through Class 1E isolation devices. The staff requested information on the qualification of the devices used for such interfaces. The applicant provided information by letters dated January 25, 1983, February 17, 1983, May 10, 1986, and June 5, 1986.

The information provided identified the maximum fault voltages which the computer communication loops could be subjected to. The test mockup was described along with identification of where the maximum fault voltages were applied during the test and how the acceptance criteria were met. The test results showed that before, during, and after the fault test, the Class 1E portion of the design continued to perform its required safety function. The staff found the qualification testing and associated test results acceptable with the exception that credit is being taken for fuses as part of the required isolation. The staff expressed concern about the interchangeability of the fuses with those of higher amperage ratings, which would negate the required protection. On the basis of this concern, the applicant has taken the following steps to allow plant operation for the first fuel cycle utilizing the fuse-dependent isolation devices:

(1) The fuse board was replaced with a terminal block requiring the use of screw-mounted fuses.

(2) Special fuse assemblies will be used whereby one end has a soldered clip attached, which will be screw mounted to the fuse termination board.

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(3) The new fuse board and fuse assembly will have a unique part number.

(4) The RDMS is the only system on site that will utilize such a fuse assembly and associated termination block.

(5) The RDMS manuals will be revised to include the new fuse assembly and associated fuse mounting board.

Further, the applicant has committed to install qualified isolation devices before startup following the first refueling outage, which will not be fuse dependent. The applicant shall submit the qualification documentation to the NRC for review before implementation.

On the basis of the satisfactory qualification testing performed and the applicant's precautionary measures taken to address the fuse interchangeability issue, the staff considers the use of the existing (fuse-dependent) isolation devices acceptable for the first cycle of plant operation. The plant operating license shall be conditioned to require that qualified non-fuse-dependent isolation devices be installed and operational before startup after the first refueling outage. This issue is considered resolved.

Software Verification and Validation

The software V&V procedures used during the design and testing of the RDMS were reviewed. The review consisted of several conference calls, document submittals, and an onsite audit at the General Atomic (GA) Technologies, Inc., office. The documents audited consisted of GA Technologies V&V procedures, the RDMS design, and the RDMS testing and qualification. The procedural portion of the review included two steps. First, the GA Technologies V&V procedures (in their entirety) were specifically reviewed followed by an assessment of their use and effectiveness related to the Seabrook RDMS design.

On the basis of the review performed, the staff concluded that the V&V procedures established by GA Technologies for the RDMS are comprehensive and sufficiently address the requirements associated with the design and testing of highly reliable systems. Spot checks of the V&V documentation specific to Seabrook confirmed that the GA Technologies V&V procedures have been utilized.

Two recommendations are warranted as a result of the staff's review. The first arises from the fact that a plant-specific RDMS design is based on previous project-specific system designs. Thus, the applicant should ensure that GA Technologies continues to assess the adequacy of the process used to determine the impact of deficiencies or modifications associated with previous project-specific RDMS designs from which the Seabrook design evolved.

The second recommendation is related to programmable read only memory (PROM). On entry into the software library, the project-specific PROM is traceable through version/revision identification. Following entry into the library, the PROM version/revision for each Seabrook RDMS monitor type is provided in a document entitled "Firmware Configuration." System acceptance test procedures require the utilization of the firmware configuration document. It is necessary that the correct version/revision of a PROM be used when an acceptance test procedure is being performed. Thus, the applicant should ensure that

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appropriate steps are taken by GA Technologies to make sure that use of the firmware configuration document will result in use of the correct version/revision of a PROM. By letter dated June 26, 1986, the applicant has committed to do so.

On the basis of the above discussion, the staff considers the V&V procedures used during the design and testing of the Seabrook Class 1E RDMS adequate. This issue is, therefore, considered resolved.

### 7.5.2.4 Postaccident Monitoring Instrumentation

The applicant was requested by Generic Letter 82-33 to provide a report to the NRC describing how the postaccident monitoring instrumentation meets the guidelines of RG 1.97 as applied to emergency response facilities. The applicant's response to RG 1.97 was provided by letter dated August 30, 1985, and Revision 58 of the FSAR.

EG&G Idaho, Inc., under contract to the NRC, with general supervision by the NRC staff, performed a detailed review and technical evaluation of the applicant's submittals. This work was reported by EG&G in the Technical Evaluation Report (TER), "Conformance to Regulatory Guide 1.97, Seabrook Station, Unit Nos. 1 and 2," dated May 1986 (attached as Appendix L to this supplement). The staff has reviewed this report and concurs with the conclusion that the applicant either conforms to, or has adequately justified deviations from, the guidance of RG 1.97 for each postaccident monitoring variable except for accumulator tank level and pressure, quench tank temperature, and containment sump water temperature.

After the generic letter was issued, the NRC staff held regional meetings in February and March 1983 to answer licensee and applicant questions and concerns regarding the NRC policy on RG 1.97. At these meetings, it was established that the NRC review would only address exceptions taken to the guidance of RG 1.97. Furthermore, if licensees or applicants explicitly state that instrument systems conform to the provisions of the regulatory guide, no staff review would be necessary for those items. Therefore, the review performed and reported by EG&G only addresses exceptions to the guidance of RG 1.97. This evaluation addresses the applicant's submittals on the basis of the review policy described in the NRC regional meetings and the conclusions of the review as reported by EG&G.

The staff has reviewed the evaluation performed by EG&G contained in the TER and concurs with its bases and findings. The applicant either conforms to, or has acceptably justified deviations from, the guidance of RG 1.97 for each postaccident monitoring variable except accumulator tank level and pressure, quench tank temperature, and containment sump water temperature.

For the variable, effluent radioactivity--noble gases, addressed in Section 3.3.5 of the EG&G TER--the applicant, by letter dated July 18, 1986, provided marked-up copies of FSAR Table 7.5-7, Sheet 12, and Page 7A-9, which reflects the change of this variable from Design Category 2 as specified in RG 1.97 to Design Category 3. The applicant's justification for this change is that the main plant vent stack noble gas radiation monitor, which is Design Category 2, provides the primary indication for detection of significant releases on breach of the containment. The containment enclosure noble gas

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radiation monitor (the instrument that measures the subject variable) is backup indication that assists the operators in identifying the location of a release that has been identified by the main plant vent stack monitor. Since backup Type C variables are considered Design Category 3, the applicant is revising the FSAR to reflect this change and will not environmentally qualify this instrument. Because the applicant is using this instrument as backup to an environmentally qualified Design Category 2 instrument, the staff agrees that it may be classified as Design Category 3 and need not be environmentally qualified.

For the variable, boric acid charging flow, addressed in Section 3.3.25 of the EG&G TER, Revision 58 of the Seabrook FSAR provided a justification for its classification as a Design Category 3 variable rather than as Design Category 2 as specified in RG 1.97. This justification was not available to EG&G at the time it was conducting its review of this item. The justification states that emergency boration is not required in the mitigation of design-basis accidents. The refueling water storage tank provides the required volume of borated water for all design-basis accidents. Emergency boration may be used to assist in the recovery, if available. Therefore, the monitoring of emergency boration flow is classified as Design Category 3. Because emergency boration flow is not a safety injection flow at this station, the staff finds that classification of this variable as Design Category 3 is acceptable.

With regard to pressurizer heater status addressed in Section 3.3.10 of the EG&G TER, the applicant, in a letter dated May 30, 1986, provided a revision to Table 7.5-1, which now indicates that this variable is categorized as Design Category 2 and is, therefore, environmentally qualified. This is in accordance with the recommendations of RG 1.97 and is, therefore, acceptable.

With regard to accumulator tank level and pressure addressed in Section 3.3.7 of the EG&G TER, the applicant, by a letter dated June 6, 1986, has committed to install an environmentally qualified accumulator tank level or pressure instrument that meets the requirements for a Category 2 instrument contained in RG 1.97. In the letter, the applicant also has committed to install an environmentally qualified containment sump water temperature instrument that meets the Category 2 RG 1.97 requirements. Containment sump water temperature is addressed in Section 3.3.17 of the EG&G report. The applicant has committed to install these instruments before startup following the first refueling outage. The staff finds these commitments acceptable.

With regard to the quench tank (pressurizer relief tank (PRT)) temperature addressed in Section 3.3.11 of the EG&G TER, the applicant is supplying a temperature range of 50°-250°F, which deviates from the recommended range of 50°-750°F. The applicant's justification is that the PRT temperature measurement is used in conjunction with PRT level and pressure indication to determine if PRT conditions are normal. The applicant states that the temperature range provided is sufficient to indicate a change from normal operating conditions, and fully enveloping the expected temperature to be encountered is not necessary in this case. The staff finds that the applicant's justification is not acceptable. The applicant should show that the indication of temperature, including the maximum expected saturation temperature, will remain functional and on scale during any accident that lifts the pressurizer relief valves, or provide a range that will envelop these conditions.

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### Conclusion

On the basis of the staff's review of the TER and the applicant's submittals, the staff finds that the design for Seabrook Units 1 and 2 is acceptable with respect to conformance to RG 1.97, Revision 3, except for the accumulator tank level and pressure instrumentation, containment sump water temperature instrumentation, and quench tank temperature instrumentation.

The applicant's commitment to install a Category 2 accumulator tank level or pressure instrument and a Category 2 containment sump water temperature instrument before startup from the first refueling outage will bring the design of these instruments into conformance with RG 1.97. The staff, therefore, finds this commitment acceptable.

For the quench tank temperature indication, the applicant should show that the indication of temperature, including the maximum expected saturation temperature, will remain functional and on scale during any accident that lifts the pressurizer relief valves, or provide a range that will envelop these conditions. If an expanded range is necessary, it should be installed before startup from the first refueling outage. In a letter dated June 24, 1986, the applicant agreed to meet this commitment, and the staff finds this acceptable.

## 7.6 Interlock Systems Important to Safety

### 7.6.7 Specific Findings

#### 7.6.7.6 Transfer From the Injection to the Recirculation Phase

As required by the SER, the applicant has provided formal information by letters dated February 14, 1986, and May 10, 1986, to verify that the safety injection (SI) signal will set a latching relay that will require separate action to reset after the SI signal has been reset. Lights have been incorporated on the main control board to indicate when the relay is latched. The applicant has confirmed that the lights' operability will be verified periodically as part of the Technical Specification surveillance requirements. The staff finds this design acceptable and, therefore, considers this issue resolved.

# 8 ELECTRICAL POWER SYSTEMS

## 8.3 Onsite Power Systems

### 8.3.1 Onsite AC Power System Compliance With GDC 17

### 8.3.1.8 Automatic Transfer of Loads and Electrical Interconnection Between Redundant Divisions

Input Signal to Computer Intelligent Remote Terminal Unit

In Supplement No. 4, the staff stated that inadvertent application of 120 V ac within the intelligent remote termination units (IRTUs) and resistance temperature detector/thermocouple conversion cabinets (RTD/TCCCs) to the field input devices, which are associated with Class 1E equipment, could result in a detrimental interaction between redundant separation groups because these inputs are not processed through qualified isolation devices. For these field input devices, the applicant provided an analysis to demonstrate that there are no detrimental interactions between redundant separation groups as a result of failures in IRTU and RTD/TCCC equipment. The staff required the applicant to perform an actual test to substantiate the conclusions of the analysis. The specific test required was to demonstrate that the maximum voltage and currents that are available in IRTUs and RTD/TCCCs have no adverse effect on the field input devices so that the Class 1E train with which the devices are associated will continue to perform the required safety function before, during, and after the application of maximum credible voltages and currents.

By letter of April 25, 1986, the applicant submitted the above test results. The analysis and test results were evaluated by EG&G Idaho. The results of the EG&G evaluation and assessment are presented in a Technical Evaluation Report (TER) attached as Appendix O to this supplement. The staff has reviewed this TER and agrees with the technical evaluation and conclusions contained in the report. On this basis, the staff considers this item resolved.

### 8.3.3 Common Electrical Features and Requirements

### 8.3.3.3 Physical Independence: Compliance With GDC 17

By letter dated March 31, 1986, the applicant proposed changes to FSAR Chapter 8 regarding physical independence criteria for the redundant ac and dc power systems. In the FSAR, the applicant committed to meet the recommendations of Institute of Electrical and Electronics Engineers (IEEE) Standard 384-1974 as endorsed by RG 1.75, Revision 2, for electrical cable and raceway separation. These documents provide two options to establish separation criteria: (1) use the guideline criteria given in these documents, or (2) provide an analysis based on a test program to justify less separation than that specified by the guideline. The FSAR indicates that the applicant used the guideline separation criteria. However, problems developed during plant construction in certain areas that caused the applicant to propose revised separation criteria that are now based on both the guideline criteria and an analysis and test program.

The results of a test program and other associated information supporting the revised criteria were included with the above-proposed request. The test program was conducted for the applicant by Wyle Laboratories and reported in Wyle Test Report 47966-02.

The staff of EG&G Idaho evaluated the results of the test program and assessed the acceptability of the proposed revised separation distances. The results of the EG&G evaluation and assessment are presented in a Technical Evaluation Report attached as Appendix P to this supplement. The staff has reviewed this TER and agrees with the technical evaluation and conclusions contained in the report. On this basis, the staff finds the applicant's proposed revised separation criteria acceptable.

# 9 AUXILIARY SYSTEMS

## 9.1 Fuel Storage and Handling

### 9.1.5 Overhead Heavy Load Handling System

NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," published July 1980, provides the results of the staff's review of the handling of heavy loads under Generic Task A-36, "Control of Heavy Loads Near Spent Fuel." Following the issuance of NUREG-0612, a generic letter, dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits, requesting that responses be prepared indicating the degree of compliance with the guidelines of NUREG-0612. The applicant reviewed its provisions for the handling and control of heavy loads and determined the extent to which the guidelines of NUREG-0612 are satisfied. By submittals dated September 24 and November 8, 1982, June 20, 1983, September 20 and October 31, 1985, and March 31 and June 4, 1986, the applicant responded to the generic letter.

The staff and its consultant, the Idaho National Engineering Laboratory (INEL), reviewed the applicant's submittals for Seabrook 1 and 2. INEL has documented its review in the Technical Evaluation Report (TER) attached as Appendix N to this supplement. The TER identifies one open item regarding load-handling procedures. By letter dated October 31, 1985, the applicant stated that load-handling procedures have been developed in accordance with Section 5.1.1 of NUREG-0612. The staff finds that the applicant has satisfactorily resolved this concern.

The applicant has also responded to a staff concern regarding the failure of heavy load attachment points for such components as the reactor head and upper internals, the reactor coolant pump motor, reactor coolant pump removable concrete plugs, and the plug for the in-core detector drive. The applicant has stated that these structures are designed with a minimum safety factor of 6, based on ultimate strength. Furthermore, the movement of these structures during refueling follows safe load paths in accordance with station procedures to preclude dropping heavy loads on safety-related equipment. Therefore, adequate protection is provided against damage to the fuel from postulated load-handling events. The staff finds the applicant's resolution of this concern acceptable.

In the June 4, 1986, submittal, the applicant stated that the weight of a heavy load for the Seabrook facility (as defined in NUREG-0612) is greater than 2100 lb, not 2000 lb as stated in earlier submittals, with one exception. The exception is the manipulator crane main hoist, for which a heavy load is defined as being greater than 2650 lb. The staff has reviewed the applicant's resolution of this concern and finds it acceptable.

The staff has reviewed the INEL TER and concurs with its findings. The TER is considered a part of this safety evaluation. On the basis of the findings of the TER and the foregoing discussion on the resolution of residual staff

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concerns, the staff concludes that the guidelines of NUREG-0612, Section 5.1.1, have been satisfied. Therefore, the applicant's response to the Phase I recommendations of NUREG-0612 is acceptable. In addition, the staff concludes that no further action is required concerning the Phase II recommendations of NUREG-0612.

## 9.3 Process Auxiliaries

### 9.3.4 Chemical and Volume Control System

### 9.3.4.2 Evaluation

### II.B.3 Postaccident Sampling Capability

In Supplement No. 3, the staff concluded that the applicant's proposed post-accident sampling system (PASS) met 7 of the 11 criteria in Item II.B.3 of NUREG-0737. The four criteria that were not fully resolved were:

(1) Criterion (2)--provide a core damage estimate procedure to include radionuclide concentrations and other physical parameters as indicators of reactor core damage.

(2) Criterion (5)--provide PASS capability to analyze for chloride by a method with the required sensitivity in the presence of anticipated interfering species and a minimum detectable threshold of 0.15 part per million chloride.

(3) Criterion (6)--provide information on the radiation exposures to individuals from the collection and analysis of reactor coolant and containment atmosphere samples.

(4) Criterion (10)--(a) develop more sensitive methods for chemical radiological analyses; (b) provide information on ranges and accuracies for these analyses demonstrating applicability of the procedures and instrumentation in the postaccident water chemistry and radiation environment; and (c) retrain operators on a semiannual basis.

By letters dated March 6, March 31, April 17, and April 22, 1986, the applicant provided additional information on the proposed PASS concerning the above criteria.

### Criterion (2)

The applicant provided a procedure for estimating the extent of reactor core damage that is based on the measurement of radioactive fission product concentrations in the reactor coolant and containment atmosphere. The procedure also takes into consideration other physical parameters as indicators of reactor core damage, such as the hydrogen concentration in the containment atmosphere, the core exit thermocouple temperature, and the containment atmosphere radiation levels. The staff finds that these provisions meet Criterion (2) in Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

Criterion (5)

The Seabrook service water system uses seawater for cooling water, but the design provides a double barrier between the primary coolant system and the seawater. Grab sample analysis for chloride on diluted primary coolant liquid samples will be completed within 96 hours of drawing the sample. Chloride concentrations in the liquid samples are determined by ion chromatography, which has a detection limit of 10 parts per billion. The sample can be diluted by as much as a factor of 15 and still provide the required minimum detectable threshold for chloride.

The PASS can dilute samples by as much as a factor of 1000 for as-low-as-is-reasonably-achievable (ALARA) purposes, which would result in a chloride detection threshold of 10 parts per million. The PASS can also take an undiluted sample, which would be retained for up to 30 days before analysis for short-lived radioactivity decay, consistent with ALARA considerations.

The staff concludes that these provisions meet Criterion (5) in Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

Criterion (6)

The applicant has performed a shielding analysis to ensure that radiation exposure from reactor coolant and containment atmosphere sampling and analysis activities is within the acceptable limits of 5 rem whole body and 75 rem extremities to the operator. The operator exposure will include entering and leaving the sample panel area, operating the sample panel manual valves, performing manual sample dilutions, and transferring samples to the chemistry laboratory for analysis. The staff has determined that these provisions meet Criterion (6) in Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

Criterion (10)

The accuracies, ranges, and sensitivities of the PASS instruments and analytical procedures are consistent with the recommendations of RG 1.97, Revision 3, and the clarifications of NUREG-0737, Item II.B.3. Therefore, they are adequate for assessing the radiological and chemical status of the reactor coolant. The instrumentation was selected for its ability to operate in the postaccident sampling environment. Equipment used for postaccident sampling and analysis will be calibrated or tested at least once every 6 months. Retraining of operators for postaccident sampling is scheduled at a frequency of once every 6 months. The staff finds that these provisions meet Criterion (10) in Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

Conclusion

On the basis of the above evaluation, the staff concludes that the applicant's proposed PASS meets all 11 criteria in Item II.B.3 of NUREG-0737 and is, therefore, acceptable. The previously proposed license condition on the PASS can now be removed.

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## 9.5 Other Auxiliary Systems

### 9.5.1 Fire Protection

In Supplement No. 4, the staff identified the following unresolved fire protection items:

(1) concerns raised during the staff's January 27 to 31, 1986, plant site audit of the fire protection program for Seabrook Station, Unit 1

(2) concerns about multiple high-impedance faults

(3) emergency lighting deviations

By letters dated March 18, April 24, May 13, and June 13, 1986, the applicant addressed the staff's plant site audit and concerns about multiple high-impedance faults. The staff has also completed its review of the emergency lighting deviations requested by the applicant in a letter dated January 24, 1986. By letter dated June 11, 1986, the applicant submitted a proposed FSAR amendment for staff review.

#### 9.5.1.1 Fire Protection Program Requirements

By letter dated June 11, 1986, the applicant submitted a proposed revision to FSAR Section 9.5-1. This revision will (1) incorporate the fire protection program that has been approved by the staff, including the fire hazards analysis and commitments that form the basis for the fire protection program, into the FSAR by reference to specific previous submittals, and (2) include a commitment to establish limiting conditions for operation, action statements, and surveillance requirements for the fire protection program within the Seabrook plant operating procedures. The applicant stated that these procedures will provide a level of protection equivalent to that provided by the fire protection sections of the Westinghouse Standard Technical Specifications (NUREG-0452). Furthermore, in the June 11, 1986, letter, the applicant committed to incorporate this revision to Section 9.5-1 into the Seabrook FSAR by means of a future amendment.

The revision to FSAR Section 9.5-1 proposed by the applicant meets the guidance for operating license applications currently under review, as set forth in Generic Letter 86-10, dated April 24, 1986. On this basis, and on the basis of the applicant's commitment, the staff finds the FSAR revision proposed by the applicant in the June 11, 1986, letter acceptable.

By letter dated March 18, 1986, the applicant identified seven deviations from the National Fire Protection Association (NFPA) standards. The deviation concerning the fire protection booster pump is discussed in Section 9.5.1.5 of this supplement. The remaining six deviations are not applicable to the nuclear industry, are consistent with staff fire protection guidelines, or, in the staff's opinion, do not decrease the level of fire protection safety. These six deviations from the NFPA standards are, therefore, acceptable.

### 9.5.1.4 General Plant Guidelines

#### Building Design

During the January 27-31, 1986, audit of the applicant's fire protection program, the staff observed that composite gypsum board-tube steel barriers were installed as fire barriers (walls) in several plant areas.

Fire test results were not available during the audit to substantiate the fire resistance rating of the barrier design. By letter dated April 24, 1986, the applicant submitted fire test reports on the subject barriers for staff review.

The subject fire barriers consist of a structural steel support system supporting four layers of type X gypsum wallboard. All vertical joints are staggered and are taped and covered with a layer of joint compound. Steel subgirts are mechanically fastened to each face of the wallboard panels. Interlocking steel siding panels are mechanically fastened to the subgirts. Butyl-based sealing gaskets are applied to all interlocking vertical joints between the siding panels on both faces of the wall assembly. On one face of the wall assembly (exposed steel face), the metal siding panels are insulated with unfaced, fiberglass compression-fit insulation bolts. A layer of regular asphaltum painted diamond mesh is erected over the exposed portions of the structural steel support system. The mesh is covered with a 1-in. layer of an approved fire retardant material.

Both sides of the wall assembly were tested by a recognized testing laboratory in accordance with American Society for Testing and Materials (ASTM) E-119-83, "Standard Methods of Fire Tests of Building Construction and Materials," in two separate tests. Both the exposed steel face and the smooth face satisfactorily withstood the fire endurance portion of the test for the full 3-hour test period. Immediately after the fire exposure, each test specimen was subjected to the standard hose stream test. Only the smooth face successfully resisted the hose stream test without developing any openings. The hose stream penetrated a small section of the exposed steel wall face between the vertical edge channel flashing and the concrete block of the test furnace through a fire retardant coating filled gap. No other section of the wall assembly was penetrated by the hose stream. The details of the wall assembly that allowed direct passage of water have been modified by the applicant with Underwriters Laboratories (UL)-approved flashing details.

On the basis of the subject fire test reports and the modified flashing details, the staff concludes that the composite tube steel-gypsum wallboard fire barriers (walls) enclosing certain Seabrook fire areas are 3 hour fire rated, meet Section C.5.a of Branch Technical Position (BTP) CMEB 9.5-1, and are, therefore, acceptable.

During the audit, the staff also noted that a number of fire door assemblies installed in fire barriers, for which deviations had not been approved, were not tested and approved by a nationally recognized testing laboratory. Fire test results were not available during the audit to verify the fire rating of the door assemblies. In the April 24, 1986, letter, the applicant also submitted a fire test report on a swinging steel door assembly. The door assembly was tested by a nationally recognized laboratory in accordance with ASTM E-152-81, "Standard Methods of Fire Tests of Door Assemblies." The door assembly remained in place without undue warpage throughout a fire exposure period of 3 hours and during a standard hose stream exposure.

On the basis of the staff's review of the referenced fire test report, the staff concludes that the tested fire door assembly achieved a fire resistance rating of 3 hours. The use of these doors in fire barriers meets Section C.5.a of BTP CMEB 9.5-1 and is, therefore, acceptable.

During the plant site audit, the staff also observed a number of fire barrier penetrations, i.e., bus duct penetrations and seismic gaps, that were not protected by penetration seal designs qualified by fire test.

By letter dated March 18, 1986, the applicant requested a deviation from Section C.5.a of BTP CMEB 9.5-1 to the extent that it states that penetrations in fire-rated barriers should be sealed to provide a fire resistance rating at least equal to that of the barrier itself for bus duct penetrations in the east wall of the nonessential switchgear room and the north wall of the turbine building.

Aluminum bus ducts penetrate the east 3-hour-fire-rated wall of the nonessential switchgear room (fire area CB-F-1A-A) to the turbine building (fire zone TB-F-1A-Z). Fire-rated seals are provided around the ducts where they penetrate the fire wall. There are no internal fire seals in the bus ducts. There is an areawide fire detection system in the nonessential switchgear room and an area sprinkler system on the turbine building side of the wall.

Aluminum bus ducts also penetrate the north 3-hour-fire-rated exterior wall of the turbine building to the outside transformer yard area. The walls are sealed around the bus ducts where they penetrate the fire wall. There are no seals inside the ducts. There is an area sprinkler system on the turbine side of the wall. Each of the transformers on the exterior side of the wall, which are located about 28 ft from the wall, is equipped with a deluge system.

The staff was concerned that a fire in one of the subject fire areas would spread to the adjacent fire area through the unsealed bus duct penetration and adversely affect safe shutdown. However, the staff evaluated the fire hazards and fire protection features provided on each side of each of the bus duct penetrations and found no unmitigated fire hazards in their proximity that present a threat to the safe shutdown capability. Moreover, in the staff's opinion, the bus ducts are capable of confining the effect of a fire to the area of origin until the fire brigade arrives and extinguishes the fire. On these bases, the staff concludes that the installation of fire-rated seals inside the subject bus ducts would not significantly increase the level of fire safety. The lack of such seals is, therefore, an acceptable deviation from Section C.5.a of BTP CMEB 9.5-1.

By letter dated April 24, 1986, the applicant also provided additional information on the seismic gaps. The seismic gaps were originally sealed with a non-fire-rated sealant material. This material has been removed and replaced with a fire-retardant silicone foam sealant material to a depth of 7-1/2 in. as described in the applicant's letter. The seismic gap seal design used by the applicant has not been tested in accordance with the ASTM E-119 fire test standard, and, therefore, does not have a fire resistance rating. However, ASTM E-119 fire tests on this silicone foam material in other configurations demonstrate that 7-1/2 in. of the sealant material can achieve a fire resistance rating of up to

3 hours. On the basis of this testing, a review of the applicant's submittal, and an evaluation of the fire hazards near the seismic gaps, the staff concludes that the silicone foam seismic gap seals installed at Seabrook Station will, for anticipated fires, prevent the spread of the fire and its products through the seismic gaps. The seismic gap seals are, therefore, acceptable.

By letter dated March 18, 1986, the applicant informed the staff that a Teflon coating has been applied to the blade guide flanges of the fire damper assemblies installed at Seabrook Station. This deviates from the UL-tested configuration in that the damper assemblies were not tested with the Teflon coating. The purpose of the Teflon coating is to improve the closure characteristics of the dampers under air flow conditions.

Section 5 of UL Standard 555, "Standard for Fire Dampers and Ceiling Dampers," allows the use of epoxy or alkyd-resin type or other outdoor paint on steel parts used in the damper assembly. The staff concurs with the applicant that the Teflon coating used is sufficiently similar to a paint coating that its use would not adversely affect the ability of the dampers to prevent fire spread and does not affect the fire rating of the fire damper assemblies. The use of the Teflon coating is, therefore, acceptable.

### Safe Shutdown Capability

During the audit of the applicant's fire protection program for Seabrook Station, the staff observed that structural steel supporting a number of fire barriers was not protected to provide fire resistance equivalent to that required of the barrier in accordance with Section C.5.b of BTP CMEB 9.5-1.

By letter dated April 24, 1986, the applicant informed the staff that it had evaluated fire barriers supported by unprotected structural steel to determine whether or not they are capable of withstanding anticipated fire exposures. On June 12, 1986, the staff met with the applicant to discuss the evaluation. By letter dated June 13, 1986, the applicant provided additional information.

The applicant's structural steel evaluation consisted of three parts. First, the potential fire area and localized fire exposure temperatures were determined for the various fires that could occur in each fire area, and second, the effects of these temperatures on the structural steel members present in each fire area were assessed. Where the calculations indicated that the steel temperatures would exceed 1100°F, the structural member was assumed to fail. Where the unprotected steel temperature did not reach 1100°F, the structural member is considered acceptable and protection is not deemed necessary. The methodology employed in these first two parts of the applicant's three-part analysis is the same as that used by Philadelphia Electric Company for Limerick Generating Station, Units 1 and 2. The staff's evaluation and acceptance of this methodology is reported in Supplement No. 2 to the Limerick SER (NUREG-0991), dated October 1984. The staff finds that the use of that methodology is appropriate and acceptable for the Seabrook facility as well.

The third part of the applicant's analysis consisted of a structural integrity review. For the fire areas where the aforementioned calculations indicated that structural members could fail as a result of fire exposure, a structural integrity review was conducted on the fire area. For each fire area in question, it was assumed that those steel members that could potentially be lost, were lost,

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and the structural integrity of the remaining structure was analyzed. Where it was determined that the structural integrity of the fire area would not be compromised by failure of the structural elements, the steel was not protected. Those structural steel members that were determined to be required to ensure the structural integrity of the area have been protected in accordance with Section C.5.b of BTP CMEB 9.5-1.

On the basis of both this evaluation and the aforementioned Limerick evaluation, the staff concludes that the absence of fire protection for the structural steel elements identified in the applicant's April 24, 1986 letter is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

In Supplement No. 4, the staff expressed a concern that fire-induced, multiple high-impedance faults could result in the loss of the necessary power supply for safe shutdown equipment. By letter dated May 13, 1986, the applicant provided additional information.

Multiple high-impedance faults can occur when several cables from a common bus are located in the same fire area. When a fire occurs in such an area, the resulting fire damage could cause electrical faults in the cables, but the faults may not trip the individual circuit breakers. However, the sum of the faults may be sufficient to trip the main breaker, which protects the power supply bus. If safe shutdown equipment is energized from the same bus, once the main breaker trips, this equipment will have lost its power source. The applicant stated that, for such a condition to occur, each branch circuit cable would have to fail along its length so as to result in a unique insulation resistance. This unique resistance would produce a leakage current to ground or conductor to conductor which, when added to the conductor load, would result in a current just below the protective device rating. Thus, an improbable combination of temporary leakage currents would have to occur at once to produce a trip of the main breaker. The applicant committed to add a general note to the safe shutdown and cooldown procedures to alert plant personnel to clear nonessential loads from a tripped bus before reclosing the bus feeder breaker, should the bus feeder breaker trip.

The staff finds the applicant's provision of the note to drop the nonessential loads before reclosing a tripped breaker acceptable in that it resolves the problem of a breaker trip because of high-impedance faults.

Ventilation

In the SER, the staff reported that charcoal filters have been provided with low-flow air bleed systems in accordance with RG 1.52. During the audit of the applicant's fire protection program for Seabrook Unit 1, the staff observed that only those charcoal filters that have been designated as engineered safety features (ESFs) have air-bleed systems. By letter dated March 18, 1986, the applicant requested a deviation from installing fire suppression systems to protect eight charcoal filters including both ESF and non-ESF filters. The applicant indicated that an analysis was conducted which showed that the temperature for adsorber autoignition or desorption would not occur even without air flow across the adsorbers. Previously, the Safety Analysis Report indicated that a low-flow air-bleed velocity of 0.2 ft per minute was required to maintain the

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adsorber temperature below the autoignition or desorption point. Staff discussions with the applicant concerning its analysis indicate that certain assumptions used in the analysis require further justification.

Staff review of this issue is still in progress. The resolution of this issue will be provided in a future supplement to the SER before an operating license is issued. This is an open item.

## Lighting and Communication

In the SER, the staff reported that the applicant committed to install 8-hour battery-powered emergency lighting units in all areas of the plant that may need to be staffed for safe shutdown operations, and in access and egress routes to and from all such areas, in accordance with Section C.5.g of BTP CMEB 9.5-1.

By letter dated January 24, 1986, the applicant requested deviations from Section C.5.g of BTP CMEB 9.5-1 in the control room, switchgear room A, and switchgear room B. In Supplement No. 4, the staff reported that its review of these deviation requests was ongoing. Following is the staff's evaluation of these deviations.

In the control room (fire area CB-F-3A-A) diesel generator-powered lighting is provided to illuminate the face of the main control board and the control switches used to achieve safe shutdown. This lighting is powered from both diesel generators in an "A and/or B" logic so that lighting is provided by either train. The diesel generator engine rooms are separated from each other by 3-hour-fire-rated barriers. Power from each diesel generator is routed to separate switchgear rooms (A and B), which are separated from each other and from the diesel generator rooms by 3-hour-fire-rated barriers. Power from each switchgear room is routed via embedded conduit on opposite sides of the control building to train A and train B essential lighting panels within the control room complex computer room. Therefore, the staff finds at least one train of power will be available for control room emergency lighting for any postulated fire outside the control room complex.

In the event of a computer room fire, both essential lighting panels could be damaged. However, in the event of such a fire, the control room will be evacuated and the remote shutdown system (RSS) control panels will be used to achieve shutdown. Emergency lighting for access and egress routes from the control room to the RSS facilities is provided by 8-hour battery-powered lights in accordance with Section C.5.g of BTP CMEB 9.5-1.

Eight-hour battery-powered emergency lighting units are provided in switchgear room A for all RSS control locations and access/egress routes thereto, with the exception of EDE-MCC-512, EDE-MCC-515, and EDE-MCC-521. These panels (motor control centers (MCCs)) are illuminated by fluorescent light fixtures powered by the train B diesel generator. The power feeds to these light fixtures are confined to switchgear rooms A and B, which are separated from each other and from each diesel generator room by 3-hour-fire-rated barriers. Therefore, the lighting in switchgear room A will not be disabled by a fire outside the switchgear rooms and the diesel generator rooms. Moreover, access to these MCCs is not required for a fire in either switchgear room or diesel generator room.

Eight-hour battery-powered emergency lighting units are provided in switchgear room B for all RSS control locations and access/egress routes thereto, with the exception of EDE-MCC-612, EDE-MCC-621, and EDE-MCC-622, which are illuminated by fluorescent lighting fixtures powered by the train B diesel generator. The power feeds to these fixtures are confined to switchgear room B, which is separated from diesel generator room B by 3-hour-fire-rated barriers. Therefore, the lighting in switchgear room B will not be disabled by a fire outside switchgear room B or diesel generator room B. Access to these MCCs is not required for a postulated fire within either switchgear room B or diesel generator room B.

On the basis of this review, the staff concludes that the installation of 8-hour battery-powered lighting units in the control room and additional 8-hour battery-powered lighting units in switchgear room A and switchgear room B would not significantly increase the level of fire safety. The staff further concludes that the lack of 8-hour battery-powered lights in these areas is an acceptable deviation from Section C.5.g of BTP CMEB 9.5-1.

### 9.5.1.5 Fire Detection and Suppression

#### Fire Detection

In the SER and in Supplement No. 4, the staff evaluated and approved deviations from Section C.6.a of BTP CMEB 9.5-1 to the extent that it states that fire detectors should be installed in all safety-related areas. By letter dated March 18, 1986, the applicant requested a deviation from Section C.6.a of BTP CMEB 9.5-1 for the space above the control room suspended ceiling.

Smoke detectors are installed in the control room at ceiling level and in the main control room console. Smoke detectors are not installed in the space above the control room suspended ceiling. The ceiling space is devoid of combustible materials and does not contain any safety-related equipment. Furthermore, the control room is continuously manned.

Because the ceiling space is devoid of combustible materials, the staff does not expect a fire to occur in this space. In the unlikely event that a fire should occur, it would be detected by the control room operators or by the existing ceiling-level smoke detection system. Because the ceiling space does not contain any safety-related equipment and is separated by the noncombustible suspended ceiling from the safety-related equipment installed in the control room, the staff does not expect any postulated fire in the ceiling space to damage safety-related components before it is detected and extinguished. In the unlikely event a fire above the control room suspended ceiling results in the loss of redundant safety-related or safe shutdown-related components, safe plant shutdown can be achieved and maintained from the remote shutdown stations. On these bases, the staff concludes that the lack of smoke detectors in the control room ceiling space is an acceptable deviation from Section C.6.a of BTP CMEB 9.5-1.

#### Fire Protection Water Supply System

A backup to the normal fire protection system has been provided for the standpipes servicing safety equipment in the event of a safe shutdown earthquake (SSE) in accordance with Section C.1.c of BTP CMEB 9.5-1. A permanent connection between one train of service water and the safety-related area standpipe

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is provided with a booster pump to supply the required flow and pressure. By letter dated March 18, 1986, the applicant informed the staff that this booster pump does not meet NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps." The fire protection booster pump is a stainless steel pump that is neither UL listed nor Factory Mutual (FM) approved. The pump includes a local on-off push button with status indication. There are a gate valve and a pressure gauge in both the suction and discharge lines of the pump.

An orifice plate is installed in a test line connecting the suction and discharge of the pump so that pump flow may be tested. A permanent flow meter is not provided, but there are connections for a portable flow meter for testing.

NFPA 20 states that fire pumps shall be listed for fire protection. Although the subject booster pump is not UL listed or FM approved (UL/FM), it has flow characteristics similar to those of a UL/FM pump. The applicant stated that UL/FM pumps are typically made of cast iron, which cannot be seismically qualified. The stainless steel booster pump, however, is seismically qualified.

NFPA 20 also states that fire pumps shall have an automatic controller, remote status indication, and remote alarm and signal devices at a point of constant attendance. NFPA 20 also requires that the interior of the suction pipe be galvanized or painted to prevent tuberculation.

The subject booster pump is not the main fire pump. It is a small (150 gpm) backup fire pump that only supplies the standpipe systems in certain plant areas in the event that an SSE damages the normal fire protection water supply. In such an event, plant operators will be dispatched to start the pump. Therefore, an automatic controller is not necessary. Moreover, the remote status indication and alarms required by NFPA 20 are not necessary because the operators will remain at the pump; in addition, because of the expected limited use of the pump, tuberculation of the pump suction is not considered a problem. On these bases, the staff concludes that the subject booster pump installation, with the identified NFPA 20 deviations, is acceptable.

### Sprinkler and Standpipe Systems

In the SER, the staff stated that hose stations are installed so that all areas of the plant can be reached with an effective hose stream with a maximum of 100 ft of hose, in accordance with Section C.6.c of BTP CMEB 9.5-1.

By letter dated March 18, 1986, the applicant requested a deviation from Section C.6.c of BTP CMEB 9.5-1 for the cooling tower, east main steam and feedwater enclosure, service water pumphouse, and the intake and discharge structures, to the extent that it states that standpipe and hose systems shall be installed so that at least one effective hose stream will be able to reach any location that contains or presents an exposure fire hazard to structures, systems, or components important to safety. The primary means of manual fire fighting for the subject areas is portable fire extinguishers. In lieu of standpipe and hose systems, the applicant proposes to use the fire hoses from the hose houses provided at the fire hydrants near these areas as a secondary means of manual fire fighting. In the staff's judgment, reliance on the hydrant hose houses instead of a standpipe system could delay the application of an effective hose stream on a fire. However, because of the limited fire hazards present in the subject areas and the separation and protection of the safety-related components in accordance with the staff fire protection guidelines as reported in the SER and its supplements, the staff does not expect this delay to adversely impact the level of fire safety. The use of portable fire extinguishers and the substitution of fire hoses from the fire hydrant hose houses for standpipe system hose is, therefore, an acceptable deviation from Section C.6.c of BTP CMEB 9.5-1.

### 9.5.1.8 Summary of Approved Deviations From BTP CMEB 9.5-1

The following deviations from BTP CMEB 9.5-1 were approved in the SER and Supplement No. 4 (SSER 4):

- carpet in the control room (SER and SSER 4)
- lack of an automatic fire suppression system and 20-ft separation between redundant safety-related equipment required for safe shutdown in certain fire areas (SER and SSER 4)
- drains in the switchgear rooms (SER)
- 1500-gal diesel fuel day tanks (SER)
- lack of independence for the alternate shutdown capability from certain fire areas (SSER 4)
- non-fire-rated wall (SSER 4)
- lack of fire dampers in certain heating, ventilation, and air conditioning ducts (SSER 4)
- non-UL-labeled dampers in certain fire areas (SSER 4)
- lack of areawide fire detection in certain fire areas (SER and SSER 4)
- fire protection water supply tanks' capacity less than 300,000 gal (SSER 4)
- non-UL-listed water supply valves (SSER 4)

On the basis of the above evaluation, the staff concludes that the following additional deviations are acceptable. The sections of this supplement in which they are discussed are enclosed in parentheses.

- deviations from NFPA standards (9.5.1.1)
- non-fire-rated bus duct penetrations (9.5.1.4)
- unprotected structural steel members in certain fire areas (9.5.1.4)
- lack of 8-hour battery-powered emergency lighting units in the control room and certain locations in switchgear rooms A and B (9.5.1.4)
- lack of smoke detectors above the control room suspended ceiling (9.5.1.5)

- deviation of certain details of the SSE fire protection booster pump from NFPA 20 (9.5.1.5)
- use of fire hydrant hose houses in lieu of standpipe hose houses for certain fire areas (9.5.1.5)

### 9.5.1.9 Conclusions

On the basis of its review, the staff concludes that, with the exception of the protection of the charcoal filter units, the applicant's fire protection program for Seabrook Station, with approved deviations, meets the staff fire protection guidelines of BTP CMEB 9.5-1 and satisfies GDC 3.

The staff will condition the operating license to require that the applicant implement and maintain in effect all provisions of the approved fire protection program.

## 9.5.8 Emergency Diesel Engine Combustion Air Intake and Exhaust System

The SER states:

> In a letter dated November 12, 1982, the applicant addressed the tornado-missile protection and protection from natural phenomena for the engine exhaust system. The applicant stated that a deflector plate will be mounted on the exhaust stack to minimize the amount of precipitation (snow, ice, rain, etc.) that could enter and accumulate in the exhaust stack. In addition, a pressure relief device will be provided to ensure diesel generator operation in the event that a tornado missile strikes the exhaust stack. Pending submittal of drawings showing the details and location of the proposed modifications, the staff finds the design modifications acceptable.

In Amendment 58 to the FSAR, the applicant modified the design of the diesel generator (DG) exhaust stacks. The new design reduces the height of an exhaust stack to 4 ft above the DG building roof and provides an exhaust hood over the exhaust stack. The staff has reviewed the design of the exhaust hood and finds that it will prevent precipitation (snow, ice, rain, etc.) from entering and accumulating in the exhaust stack. However, reducing the DG exhaust stack height to 4 ft introduced a new concern, which is a potential blockage of the stack resulting from drifting snow. The applicant, in a letter dated May 29, 1986, has described the procedures that will be used to keep a DG exhaust stack clear of snow during a storm. The staff has evaluated the information provided and finds it acceptable. The applicant states that, during the months of November through March, the exhaust stacks will be checked periodically after any significant snowfall for drifting snow and cleared as necessary to maintain the DG in an operable condition.

Amendment 58 to the FSAR also states that the DG exhaust stacks are not tornado missile protected, but that on the basis of a probability risk analysis, the probability of a tornado damaging the exhaust stacks is low. By letters dated May 29 and June 4, 1986, the applicant provided additional information in response to the staff's concern. The applicant has stated that an analysis was performed to estimate tornado missile impact probabilities on the as-built

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DG exhaust stack configuration. The results of the analysis show that the probability of a tornado missile impacting a DG exhaust stack is estimated to have a mean value of $10^{-6}$ per year. The staff finds this acceptably low.

The staff concludes that the emergency diesel engine intake and exhaust system meets the requirements of GDC 2, 4, 5, and 17. There is reasonable assurance that the emergency diesel engine intake and exhaust system will satisfactorily perform its design safety function, and is, therefore, acceptable.

# 10 STEAM AND POWER CONVERSION SYSTEM

## 10.2 Turbine Generator

### 10.2.3 Turbine Disc Integrity

By letter dated June 9, 1986, the applicant committed to adopt a turbine maintenance program recommended by the manufacturer. Further information on the maintenance program is provided in Section 3.5.1.3 of this supplement.

## 10.3 Main Steam Supply System

### 10.3.5 Secondary Water Chemistry

In Supplement No. 1 of the SER, the staff stated that the operating license should be conditioned to require that the applicant's proposed secondary water chemistry monitoring and control program be carried out. The staff has reviewed the proof-and-review copy of the Seabrook Unit 1 Technical Specifications, which contain (Section 6.7.4c) a requirement to implement a secondary water chemistry monitoring and control program. The program guidance conforms to SRP Section 5.4.2.1 (NUREG-0800).

The staff considers this technical specification acceptable in lieu of a license condition. Therefore, the license condition on secondary water chemistry discussed in Section 10.3.5 of Supplement No. 1 is no longer needed.

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# 11 RADIOACTIVE WASTE MANAGEMENT

## 11.3 Gaseous Waste Management System

Seabrook has a unique waste gas processing system, which utilizes charcoal delay beds to decontaminate waste gases. This permits recycling of the hydrogen cover gas and minimizes releases. This system could present an unusually high potential for hydrogen deflagration in the cubicles housing the waste gas system because the gas in the system is almost pure hydrogen.

The applicant contends that the consequences of such a deflagration would be relatively minor because (1) the resulting increase in radioactivity release would be inconsequential even when compared to the criteria of Appendix I, and (2) there are no safety systems in the vicinity to be affected. Furthermore, the applicant has minimized the likelihood of a deflagration by (1) installing hydrogen detectors in each cubicle, (2) providing continuous ventilation of all cubicles, and (3) having an automatic purge system to rapidly reduce the hydrogen concentration (if needed) in the cubicle containing the surge tank.

The staff has reviewed the provisions for control of explosive gas mixtures in the cubicles. On the basis of the above considerations and the assurance of availability of equipment provided by the Technical Specifications, the staff concludes that these provisions are acceptable.

## 11.4 Solid Waste Management Systems

### 11.4.1 System Description

The solid waste processing system (SWPS) is designed to process two general types of solid wastes: wet solid wastes and dry solid wastes. Wet solid wastes consist mainly of spent filter cartridges, demineralizer resins, filter sludges, chemical drain solutions, and evaporator bottoms, which contain radioactive materials removed from liquid streams during processing. Dry solid wastes consist mainly of ventilation air filtering media (high efficiency particulate air, charcoal), contaminated clothing, paper, rags, laboratory glassware, and tools.

The applicant indicated that the various wet and dry solid radioactive waste produced will be processed either by a single permanently installed solid waste management system utilizing asphalt or by using the services of a mobile solidification contractor using cement. The permanently installed system will not be completed by the Unit 1 fuel load date; therefore, contracted mobile solidification services will be used.

Spent filter cartridges will be encapsulated and solidified using either an asphalt binder or cement in 55-gal drums. The radioactive wastes in the form of slurry will be pumped either to the permanently installed asphalt evaporator/extruder or to the alternate solidification station. Spent demineralizer resin will be processed by volume reduction and solidification. Solidified wastes will be deposited into either 55-gal drums or 85-ft$^3$ containers.

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Dry active wastes will be processed in a 100-ft$^3$ box compactor with antispringback devices. The compactor exhaust system operates to prevent dust from escaping during trash handling, and will be complete with fan, fan motor, prefilter, absolute filter, and connections to the duct in the filled drum storage area exhaust system.

The applicant will have onsite storage capacity for 450 to 650 drums of solidified waste. Solid waste containers, shipping cask, and methods of packing are designed to meet applicable State and Federal regulations, including 10 CFR 71.

### 11.4.2 Evaluation and Findings

The staff has reviewed the SWPS in accordance with the acceptance criteria of SRP Section 11.4 (NUREG-0800). The scope of the review included line diagrams of the system, piping and instrumentation diagrams (P&IDs), and the system description of the SWPS and those auxiliary supporting systems that are essential to the operation of the SWPS. The applicant's proposed design criteria and design bases for the SWPS and the applicant's analysis of those criteria and bases have also been reviewed. The staff has also reviewed (1) the capability of the proposed system to process the types and volumes of wastes expected during normal operation and anticipated operational occurrences in accordance with GDC 60 and (2) provision for the handling of wastes relative to the requirements of 10 CFR 20 and 71 and applicable U.S. Department of Transportation regulations.

The staff has reviewed the mobile solidification system that will be provided by the NUS Corporation. This system was approved for reference by licensees in an NRC safety evaluation (Thomas, May 1985). This evaluation stated that utilization of this system at a facility required that certain plant-specific information be supplied. The applicant did this in a letter dated May 29, 1986. By letter dated June 17, 1986, the applicant also provided a description of liquid spill control methods, including type and location. The staff finds this acceptable.

In addition, the mobile system waste processing will be limited to the waste processing building as noted in the May 29, 1986, submittal, and the waste classification requirements of 10 CFR 61 will be met.

The asphalt system process control program (PCP) has not been approved. The PCP has not addressed

(1) methods to verify that the waste has been solidified
(2) methods for reprocessing the wastes when they are shown to be unsolidified

The PCP must be approved before the processing of waste utilizing asphalt.

The staff finds that both the mobile and inplant waste processing systems conform with the remaining acceptance criteria of SRP Section 11.4 and are, therefore, acceptable. Therefore, Outstanding Issue No. 14, "Solid Radwaste Management System," has been resolved.

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## 11.5 Process and Effluent Radiological Monitoring and Sampling Systems

### 11.5.2 Evaluation Findings

The staff questioned the lack of provision for sampling or monitoring the turbine gland steam condenser exhaust. The applicant has committed to include provisions for continuously sampling this effluent stream for radioiodines and particulates. There is no noble gas monitor because the noble gas release by this stream will be negligible compared with the release via the main condenser exhaust. The turbine gland steam condenser exhaust samplers will be required by the Technical Specifications. The staff has concluded that these provisions are acceptable.

In the SER, the staff stated that certain items would be addressed when the Radiological Effluent Technical Specifications (RETS) were submitted by the applicant. These items were

(1) sampling frequencies, required analyses, instrument alarm/type setpoints, calibration, and sensitivities

(2) frequency of routine instrument calibration, maintenance, and inspections

(3) release rates

The RETS have been submitted and, after extensive discussion, have been revised so that they are acceptable to both the applicant and the staff. The RETS do address the aforementioned items and are considered acceptable by the staff.

In a May 20, 1986, letter to the staff, the applicant addressed the clarification of Items 4a and 4b of Attachment 1, "Noble Gas Effluent Monitor," to TMI Action Plan Item II.F.1, and clarification of Items 1 through 4 of Attachment 2, "Sampling and Analysis of Effluents," to this same TMI Task Action Plan item. On the basis of a review of this submittal and FSAR Sections 7.5, 11.5, and 12.3, the staff concludes that the applicant conforms with Attachments 1 and 2 except for the capability to obtain representative samples without excessive plateout. The applicant utilizes a system that has a very low flow velocity. For those facilities that utilize this system, it has been incorporated as a license condition that, before the startup after the first refueling outage, the applicant must demonstrate that representative radioactive iodine and particulate samples may be obtained. This same license condition will be applied to the Seabrook Station.

The proposed license condition would read as follows:

> Before startup following the first refueling outage, the applicant shall demonstrate that the iodine/particulate sampling system is operable and will perform its intended function.

In Supplement No. 2, the staff identified certain items that would be reviewed as part of the review of the Offsite Dose Calculation Manual (ODCM). The staff's review is addressed below.

In a letter to the applicant dated May 20, 1986, the staff agreed to the inclusion of certain tables in the Seabrook ODCM that are in the Technical Specifications of other plants. These tables are in Part A of the Seabrook

ODCM. Part A cannot be changed without prior approval by the NRC. The tables, identified by title and Standard Technical Specification (STS) number, are in Table 11.1 of this supplement.

The staff reviewed Part A of the ODCM submitted by letter (SBN-1122) dated June 17, 1986. The applicant had proposed numerous deviations from the Standard Technical Specifications. After extensive discussions with applicant personnel, agreement was reached on mutually acceptable changes that meet both the intent of the Standard Technical Specifications and the plant-specific needs of Seabrook. The staff concludes that Part A of the Seabrook ODCM is acceptable.

Part B of the Seabrook ODCM, which constitutes the bulk of this 150-page manual, documents the methods used to meet the requirements of various Technical Specifications. The methods addressed include the following:

(1) calculating offsite radiation doses from liquid effluents, gaseous effluents, and direct radiation

(2) calculating offsite radiation dose rates from liquid and gaseous effluents

(3) calculating setpoints for process, effluent, and engineered safety features instrumentation

(4) performing the land use census

(5) conducting the environmental monitoring program

The staff has reviewed the Seabrook ODCM and noted the correction of the errors and deficiencies identified by the staff in the version submitted "for approval" by PSNH Letter 954 (March 3, 1986). The staff also notes that the approaches used are generally consistent with NRC methodology and requirements. However, not all differences between the staff and the applicant have been resolved either for Method 2 or for Method 1 gaseous releases. The unresolved differences in Method 1 are no greater than a factor of 10. These differences are compensated by a requirement in Part A of the ODCM documented by a letter from the applicant dated July 22, 1986. Part A requires that, pending resolution of the ODCM issues, only Method 1 (of Part B) will be used and that releases in gaseous effluents will be limited to no more than 10% of the quantities indicated to be permissible by Method 1. Thus, there is assurance that the limits of 10 CFR 20 and 10 CFR 50 will not be exceeded. On this basis the staff finds the ODCM acceptable.

Table 11.1 Tables in Offsite Dose Calculation Manual (ODCM)

| STS* number | Title | ODCM number |
|---|---|---|
| 4.11-1 | Radioactive Liquid Waste Sampling and Analysis Program | A.3-1 |
| 4.12-2 | Radioactive Gaseous Waste Sampling and Analysis Program | A.4-1 |
| 3.12-1 | Radiological Environmental Monitoring Program | A.5-1 |
| 3.12-2 | Reporting Levels for Radioactivity Concentrations in Environmental Samples | A.5-3 |
| 4.12-1 | Detection Capabilities for Environmental Sample Analysis | A.5-2 |

*Standard Technical Specifications (NUREG-0452).

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# 12 RADIATION PROTECTION

## 12.3 Radiation Protection Design Features

### 12.3.4 Area Monitoring and Airborne Radioactivity Monitoring Instrumentation

### 12.3.4.2 Airborne Radioactivity Monitoring Instrumentation

By a letter dated May 10, 1986, the applicant has provided information establishing an equivalent alternative to staff positions regarding airborne radioactivity monitoring as established in SRP Section 12.3-12.4 (NUREG-0800) regarding monitoring of radioactivity upstream of high efficiency particulate air (HEPA) filter banks. The applicant has included descriptions and justifications for installing ventilation monitoring downstream of the primary auxiliary building (PAB) ventilation HEPA filters, instead of upstream, and has revised FSAR Section 12.3.4.2.b.2(c) to reflect this change.

The staff has evaluated this proposed change in accordance with the intent of the SRP, namely to provide the capability to detect significant levels of airborne radioactivity in normally occupied spaces and keep potential exposures as low as reasonably achievable. The applicant's proposal is acceptable on the basis of the following evaluation:

(1) A significant portion of the PAB releases will be monitored for gross activity upstream of the HEPA filters.

(2) Noble gas monitors, which are effective upstream or downstream of the filters, can also indicate particulate and radioiodine release and should effectively detect radioactive leakage from upstream areas and systems.

(3) Air monitoring, sampling, and analyzing will be routinely performed in PAB areas through the use of mobile constant air monitors and portable air samplers.

(4) Work that could result in releases of radioactive materials will be controlled by radiation work permits, engineering controls, respiratory protection controls, and radiation protection staff oversight.

This evaluation approves the applicant's justification as an exception and equivalent alternative and revises the statement in the SER from "The applicant will also provide upstream monitoring for the PAB," to "The applicant will also provide downstream monitoring for the PAB."

## 12.5 Operational Radiation Protection Program

### 12.5.1 Organization

The staff has further reviewed the applicant's commitments in the FSAR through Amendment 56 and has reviewed Region I inspection results related to the Seabrook

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health physics organization (Inspection Report 50-443/85-28). Although the Health Physics Department Supervisor (HPDS) is two organizational levels below the Station Manager, he has direct access to him on radiation protection matters and reports through a management chain independent of operations (i.e., Technical Services).

The staff has found the Seabrook Health Physics Department organization, as well as the reporting level of the HPDS (equivalent to Radiation Protection Manager), to be in accordance with the SRP (NUREG-0800) and, therefore, acceptable. This resolves the staff concern regarding the organizational placement of the HPDS noted in Section 12.5 of the SER.

The current HPDS's qualifications have been determined acceptable on the basis of a previous review of this specific case, including personnel interviews and an evaluation of the individual's experience and qualifications. By letter dated May 10, 1986, the applicant has stated that the basic qualifications for the HPDS, other than those of the currently assigned HPDS, will meet RG 1.8 (Rev. 1), September 1975, and personnel selected as backup for the HPDS will meet American National Standards Institute/American Nuclear Society (ANSI/ANS) 3.1-1981, or equivalent. These commitments meet the staff's positions in the SRP and are acceptable. This evaluation clarifies the staff position in Section 12.5.1 of the SER, indicating that the HPDS would have "qualifications similar to those specified in RG 1.8."

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# 13 CONDUCT OF OPERATIONS

## 13.1 Organizational Structure and Qualifications

The staff visited the Seabrook Station to interview selected key management personnel in the revised corporate and operating organizations. These discussions covered on an individual basis the managers' roles, control, and coordination of their units' effort, potential problems, and their expectations of the personnel reporting to them.

The staff found the managers proud of their units and enthusiastic about carrying out their missions. There will be an extensive use of computers to track activities at all levels as well as strict configuration control to deter ad hoc actions that could result in unreviewed plant conditions. Outside review groups such as the Institute of Nuclear Power Operations and personnel from operating facilities have assessed the Seabrook organizational structure and helped define potential problem areas. In addition, corporate personnel visited other operating facilities to factor in good and bad experience of other stations in establishing policy and procedures at Seabrook. A conscious effort has been made to focus the station manager's attention on plant operation by minimizing the peripheral support functions under his jurisdiction. Communications, both vertically and horizontally, in the organization appear to be good, and the thrust is to get problems out in the open so they can be addressed. A general recurring theme in the discussions was a desire to do the job right. Many of the managers have prior power plant experience, and all exhibited confidence in discussing their functions.

The staff concludes that the operating organization and the corporate support elements are in place and functioning so as to provide assurance that Seabrook Unit 1 can be operated safely.

### 13.1.1 Management and Technical Support Organization

#### 13.1.1.1 Corporate Organization

In FSAR Amendment 58, the applicant proposed changes to the corporate organization to reflect the transition from a construction to an operating mode for Unit 1. There is a realignment and expansion of the structure reporting to the Senior Vice President of New Hampshire Yankee as shown in Figure 13.1. The responsibilities and duties of the various organizational elements encompass the activities of the previous corporate organization that were reviewed and found acceptable by the staff.

Reporting to the New Hampshire Yankee Senior Vice President are the Vice President-Nuclear Production, Vice President and Director of Quality Programs, Director of Corporate Services, Director of Management Control, Director of Engineering, and an Executive Assistant.

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The Vice President and Director of Quality Programs has been delegated the necessary authority and responsibility to implement the operational quality assurance (QA) program (OQAP). This activity will be carried out by the Nuclear Quality Group (NQG), which reports to the Vice President and Director of Quality Programs via the Nuclear Quality Manager. Previously, the NQG reported to the Vice President-Nuclear Production. This change in reporting is acceptable because it maintains the independence of the NQG from the plant operations organization. Various operational support services have been delegated to the Yankee Nuclear Services Division (YNSD); however, the NQG's authority extends over the New Hampshire Yankee corporate staff, the Seabrook Station staff, YNSD, and any other organization performing OQAP-related work for Seabrook.

The Director of Engineering is responsible for implementing engineering programs, configuration management, reliability and performance engineering, special projects, field engineering and design, and safety evaluations for Seabrook. New Hampshire Yankee has contracted with YNSD for certain operational and station support services. New Hampshire Yankee has delegated to YNSD the necessary authority and organizational freedom to accomplish these support services; however, New Hampshire Yankee retains ultimate responsibility for monitoring and approving the work.

The Director of Management Control and the Director of Corporate Services provide administrative and corporate facilities and equipment not controlled by the Seabrook Station staff.

The Executive Assistant manages the Independent Safety Engineering Group among other activities for the Senior Vice President.

The Vice President-Nuclear Production has full-time responsibility for the operation of the Seabrook Station. The Station Manager, Nuclear Services Manager, Startup Manager, and Training Center Manager report to the Vice President-Nuclear Production. This structure is essentially the same as that in the previously reviewed organization except that information systems and QA are managed by other New Hampshire Yankee entities.

In Supplement No. 4, the staff recommended that approval authority for preoperation and startup tests and test results be assigned to a management individual. In a letter dated May 29, 1986, the applicant stated that the approval authority has been assigned to the Station Manager or the Startup Manager as appropriate. The staff considers this issue closed. The staff also recommended that those individuals authorized to direct the tests have a minimum of 1 year of nuclear power plant experience. In the letter dated May 29, 1986, the applicant stated that those individuals authorized to direct tests have more than 1 year of nuclear power plant experience. The staff considers this issue closed.

Modifications to the corporate organization for the management of, and the means for providing technical support for, the plant staff during operation of the Seabrook facility have been presented in FSAR Amendment 58. The staff's review of the modifications and previous staff safety evaluations indicate that the organization is capable of providing support for the technical and programmatic areas identified in SRP Section 13.1.1. Consequently, the staff concludes that the applicant has an acceptable organization to manage and support the operation of the facility.

### 13.1.2 Operating Organization

### 13.1.2.2 Operations

In FSAR Amendment 58, the applicant modified the onsite organization to that shown in Figure 13.2. The changes from the previous organizational structure were realignment of reporting for some functional entities and creation of several intermediate managers. The staff's review of the new organization indicates that there is no substantive change in the functional activities carried out by the onsite organization.

As a result of the lessons learned from the Three Mile Island accident, the staff requires that licensees provide onshift engineering expertise. A Commission Policy Statement on Engineering Expertise on Shift allows the role of the shift technical advisor (STA) to be combined with that of one of the senior reactor operators (SROs) on shift if certain training and educational criteria are met. In FSAR Amendment 58, the applicant stated that the shift superintendents will function as STAs and provide requisite technical expertise in the event of any abnormal operational occurrence. In a letter dated February 14, 1986, the applicant noted that at least two SROs (including the shift superintendents) who are trained as STAs are on each shift. These individuals possess Bachelor of Science degrees in Liberal Studies from Regents College of the University of the State of New York. The staff has reviewed the minimum technical content of the formal college-level education of the SRO/STA candidates at Seabrook Unit 1 and has concluded that this level of technical course work satisfies the formal education criteria of the Policy Statement. Therefore, the staff considers the shift superintendents acceptable for the dual SRO/STA role.

## 13.2 Training

### 13.2.2 Training for Nonlicensed Plant Staff

### 13.2.2.1 Program Elements

In Section 13.2.2.1 of the SER, the training for shift technical advisors was briefly explained. Further information on this subject is provided in Section 13.1.2.2 of this supplement.

## 13.4 Operational Review

### 13.4.3 Independent Safety Engineering Group

In FSAR Amendment 58, the applicant changed the name of the Operational Engineering Section to Independent Safety Engineering Group (ISEG). In a letter dated May 7, 1986, the applicant noted that the ISEG has been established and functions pursuant to a charter and interface agreement approved by the New Hampshire Yankee Senior Vice President. These documents provide executive direction that the recommendations submitted by the ISEG receive appropriate consideration and action by the line and staff executives and management, and that a response is sent back to the ISEG. The ISEG will report to the Executive

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Assistant to the Senior Vice President, who has been given authority to ensure the recommendations are acted on by the appropriate elements of the organization.

The staff finds the provisions for implementing the ISEG acceptable.

## 13.5 Station Administrative Procedures

### 13.5.1 Administrative Procedures

In the SER, the staff indicated that final acceptance of the applicant's commitment to implement TMI Action Plan Item I.A.1.3, "Shift Manning," was subject to approval of the plant Technical Specifications and the acceptance of the clarifications to RG 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2 (February 1978), given in Appendix A to FSAR Chapter 17.

The staff has reviewed the proof-and-review copy of the Seabrook Technical Specifications. The minimum shift crew composition is in conformance with 10 CFR 50.54 and the clarification of TMI Action Plan Item I.A.1.3 in NUREG-0737. In addition, administrative procedures on staff working hours will be developed in accordance with the NRC Policy Statement on working hours (Generic Letter 82-12). Further, Section 6.7.1 of the Seabrook Technical Specifications states:

> Written procedures shall be established, implemented, and maintained covering the activities referenced below:
>
> a) The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

On the basis of these Technical Specifications, the staff finds the applicant in compliance with the requirements of TMI Action Plan Item I.A.1.3. The staff considers this issue closed.

## 13.6 Physical Security Plan

### 13.6.1 Introduction

The applicant has filed with the NRC for Seabrook Station Unit 1 the following security plans, which have since been amended: "Seabrook Station Physical Security Plan," "Seabrook Station Contingency Plan," and the "Seabrook Station Guard Training and Qualification Plan."

The safety evaluation report prepared by the staff summarizes how the applicant has provided for meeting the requirements of 10 CFR 73 and consists of a basic analysis that is available for public review, a protected appendix, and a protected response force size worksheet.

On the basis of its review of the subject documents and visits to the site, the staff has concluded that the protection provided by the applicant against radiological sabotage at the Seabrook Station meets the requirements of 10 CFR 73. Accordingly, the protection provided will ensure that the health and safety of the public will not be endangered.

### 13.6.2 Physical Security Organization

To satisfy the requirements of 10 CFR 73.55(b), the applicant provided a physical security organization that includes a Security Shift Supervisor who is on site at all times with the authority to direct the physical protection activities. To implement the commitments made in the physical security plan, guard training and qualification plan, and the safeguards contingency plan, written security procedures specifying the duties of the security organization members are available for inspection. The training program and critical security tasks and duties for the security organization personnel are defined in the "Seabrook Station Guard Training and Qualification Plan," which meets the requirements of 10 CFR 73, Appendix B, for the training, equipping, and qualification of the security organization members. The physical security plan and the training program provide commitments that preclude the assignment of any individual to a security-related duty or task before the individual is trained, equipped, and qualified to perform the assigned duty in accordance with the approved guard training and qualification plan.

### 13.6.3 Physical Barriers

In meeting the requirements of 10 CFR 73.55(c), the applicant has provided a protected area barrier that meets the definition in 10 CFR 73.2(f)(1). An isolation zone, to permit observation of activities along the barrier of at least 20 ft, is provided on both sides of the barrier with the exception of the locations listed in the protected appendix. The staff has reviewed those locations and determined that the security measures in place are satisfactory and continue to meet the requirements of 10 CFR 73.55(c).

Illumination of 0.2 ft-candle is maintained for the isolation zones, protected area barrier, and external portions of the protected area. In areas where illumination of 0.2 ft-candle cannot be maintained, special procedures are applied as described in the protected appendix.

The protected area is patrolled at random intervals to detect the presence of unauthorized persons, vehicles, and materials.

#### Identification of Vital Areas

The protected appendix discusses the applicant's vital area program and identifies those areas and items of equipment determined to be vital for protection purposes.

Vital equipment is located within vital areas that are within the protected area and that require passage through at least two barriers, as defined in 10 CFR 73.2(f)(1) and (2), with certain exceptions, to gain access to vital equipment. The staff has reviewed those exceptions and has determined that the barriers are sufficiently substantial to meet the intent of the two-barrier requirement. Except for the exceptions noted in the protected appendix, vital area barriers are separated from the protected area barrier. The control room and central alarm station are provided with bullet-resistant walls, doors, ceilings, floors, and windows. On the basis of these findings and the analysis in the protected appendix, the staff has concluded that the applicant's program for identification and protection of vital equipment satisfies the regulatory intent. This program is subject to onsite validation by the staff in the future and to subsequent changes if they are found to be necessary.

### 13.6.4 Access Requirements

In accordance with 10 CFR 73.55(d), all points of personnel and vehicle access to the protected area are controlled. The individual responsible for controlling the final point of access into the protected area is located in a bullet-resistant structure. As part of the access control program, vehicles, personnel, packages, and materials entering the protected area are searched for explosives, firearms, and incendiary devices by electronic search equipment and/or physical search.

Vehicles admitted to the protected area, except applicant-designated vehicles, are controlled by escorts. Applicant-designated vehicles are limited to onsite station functions and remain in the protected area except for operational maintenance, repair, security, and emergency purposes. Positive control over these vehicles is maintained by personnel authorized to use the vehicles or by the escort personnel.

A picture badge/key card system, utilizing encoded information, identifies individuals who are authorized unescorted access to protected and vital areas and is used to control access to these areas. Individuals not authorized unescorted access are issued badges without pictures that indicate an escort is required. Access authorizations are limited to those individuals who have a need for access to perform their duties.

Unoccupied vital areas are locked and alarmed. Access to the reactor containment is positively controlled to ensure that only authorized individuals are permitted to enter. In addition, all doors and personnel/equipment hatches into the reactor containment are locked and alarmed. Keys, locks, combinations, and related equipment are changed regularly. In addition, when an individual's access authorization has been terminated because of lack of reliability or trustworthiness, or poor work performance, the keys, locks, combinations, and related equipment to which that person had access are changed.

### 13.6.5 Detection Aids

In satisfying the requirements of 10 CFR 73.55(e), the applicant has installed intrusion detection systems at the protected area barrier, at entrances to vital areas, and at all emergency exits. Alarms from the intrusion detection system annunciate within the continuously manned central alarm station located in the protected area and within a secondary alarm station also located in the protected area. In addition, the central alarm station is constructed so that the walls, floors, ceilings, doors, and windows are bullet resistant. The alarm stations are located and designed in such a manner that a single act cannot interdict the capability of calling for assistance or responding to alarms. No functions or duties that would interfere with its alarm response function are performed in the central alarm station.

The intrusion detection systems' transmission lines and associated alarms' annunciation hardware are line supervised and tamper indicating. Alarm annunciators indicate the type of alarm and its location when activated. An automatic indication of when the alarm system is on standby power is provided in the central alarm station.

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### 13.6.6 Communications

As required in 10 CFR 73.55(f), the applicant has provided for the capability of continuous communication between the central and secondary alarm station operators, guards, watchmen, and armed response personnel through the use of a conventional telephone system and a security radio system. In addition, direct communication with the local law enforcement authorities is maintained through the use of a conventional telephone system and a two-way FM radio link. All nonportable communication links, except the conventional telephone system, are provided with an uninterruptible emergency power source.

### 13.6.7 Test and Maintenance Requirements

In meeting the requirements of 10 CFR 73.55(g), the applicant has established a program for the testing and maintenance of all intrusion alarms, emergency alarms, communication equipment, physical barriers, and other security-related devices or equipment. Equipment or devices that do not meet the design performance criteria or have failed to otherwise operate will be compensated for by appropriate measures as defined in the "Seabrook Station Physical Security Plan" and in site procedures. The compensatory measures defined in these plans will ensure that the effectiveness of the security system is not reduced by failures or other contingencies affecting the operation of the security-related equipment or structures.

Intrusion detection systems are tested for proper performance at the beginning and end of any period during which they are used for security. Such testing will be conducted at least once every 7 days. Communication systems for onsite communication are tested at the beginning of each security shift. Offsite communication systems are tested at least once each day.

Audits of the security program are conducted once every 12 months by personnel independent of site security management and supervision. The audits, focusing on the effectiveness of the physical protection provided by the onsite security organization in implementing the approved security program plans, include, but are not limited to, a review of the security procedures and practices, system testing and maintenance programs, and local law enforcement assistance agreements. The applicant's quality assurance and management staff prepares a report documenting its findings and recommendations and submits it to the applicant for review and necessary action.

### 13.6.8 Response Requirements

In meeting the requirements of 10 CFR 73.55(h), the applicant has provided for armed responders immediately available for response duties on all shifts consistent with the requirements of the regulations (as discussed in the protected appendix). Considerations used in support of this number are included in the protected portion of the safety evaluation report. In addition, liaison with local law enforcement authorities to provide additional response support in the event of security events has been established and documented.

The applicant's safeguards contingency plan for dealing with thefts, threats, and radiological sabotage events satisfies the requirements of 10 CFR 73, Appendix C.

The plan identifies appropriate security events that could initiate a radiological sabotage event and identifies the applicant's preplanning, response resources, safeguards contingency participants, and coordination activities for each identified event. Through this plan, on the detection of abnormal presence or activities within the protected or vital areas, response activities using the available resources would be initiated. The response activities and objectives include the neutralization of the existing threat by requiring the response force members to interpose themselves between the adversary and the objective, instructions to use force commensurate with that used by the adversary, and authority to request sufficient assistance from the local law enforcement authorities to maintain control over the situation.

### 13.6.9 Employee Screening Program

In meeting the requirements of 10 CFR 73.55(a) to protect against the design-basis threat as stated in 10 CFR 73.1(a)(1)(ii), the applicant has provided for an employee screening program. Personnel who successfully complete the employee screening program or its equivalent may be granted unescorted access to protected and vital areas at the Seabrook Station. All other personnel requiring access to the site are escorted by persons who are authorized and trained for escort duties and who have successfully completed the employee screening program. The employee screening program is based on accepted industry standards and includes a background investigation, psychological evaluation, and a continuing observation program. The plan also provides for a "grandfather clause" exclusion, which allows recognition of a certain period of trustworthy service with the utility or contractor as being equivalent to the overall employee screening program. The staff has reviewed the applicant's screening program against the accepted industry standards (American National Standards Institute Standard ANSI N18.17-1973) and has determined that the applicant's program is acceptable.

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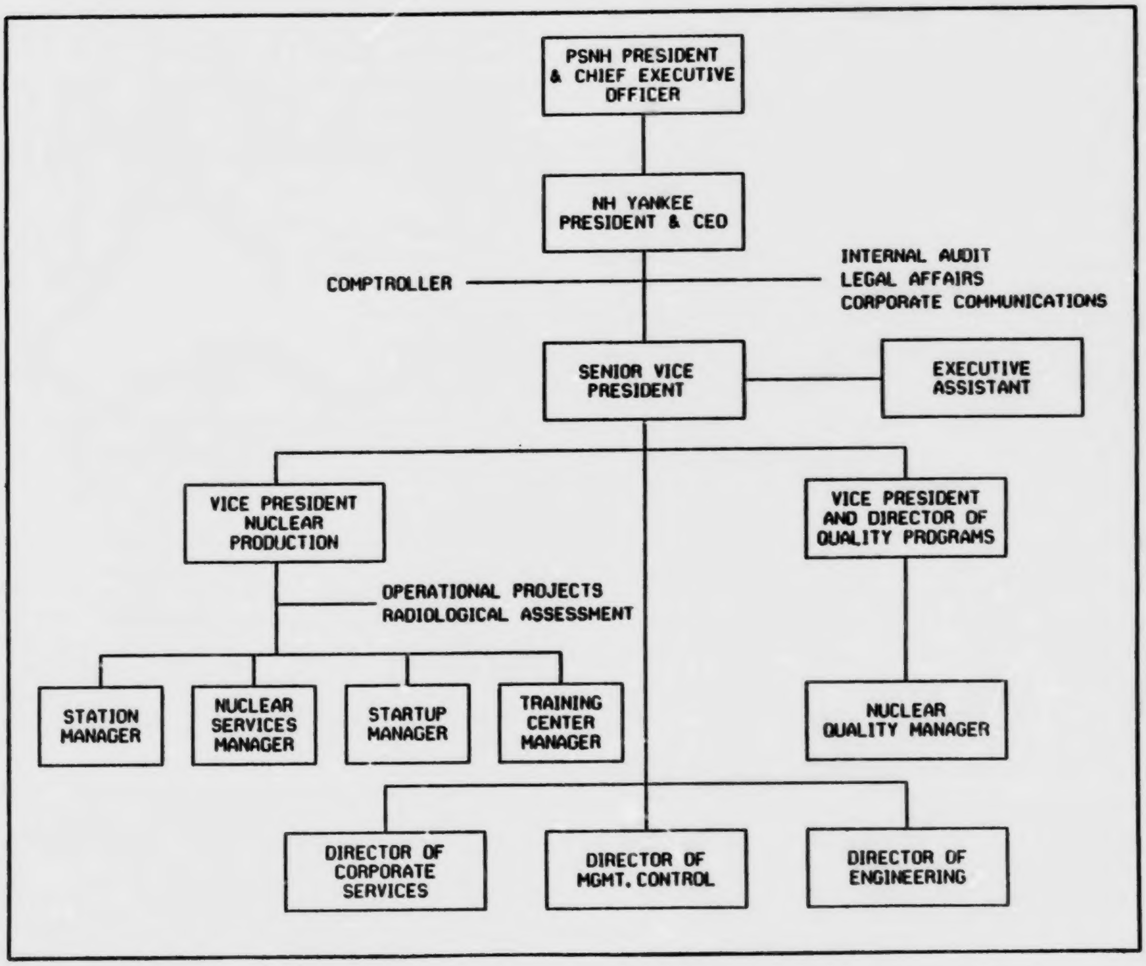
PSNH PRESIDENT & CHIEF EXECUTIVE OFFICER
NH YANKEE PRESIDENT & CEO
COMPTROLLER
INTERNAL AUDIT
LEGAL AFFAIRS
CORPORATE COMMUNICATIONS
SENIOR VICE PRESIDENT
EXECUTIVE ASSISTANT
VICE PRESIDENT NUCLEAR PRODUCTION
VICE PRESIDENT AND DIRECTOR OF QUALITY PROGRAMS
OPERATIONAL PROJECTS
RADIOLOGICAL ASSESSMENT
STATION MANAGER
NUCLEAR SERVICES MANAGER
STARTUP MANAGER
TRAINING CENTER MANAGER
NUCLEAR QUALITY MANAGER
DIRECTOR OF CORPORATE SERVICES
DIRECTOR OF MGMT. CONTROL
DIRECTOR OF ENGINEERING

Figure 13.1 New Hampshire Yankee organization
Source: FSAR Figure 13.1-1, Amendment 58, April 1986

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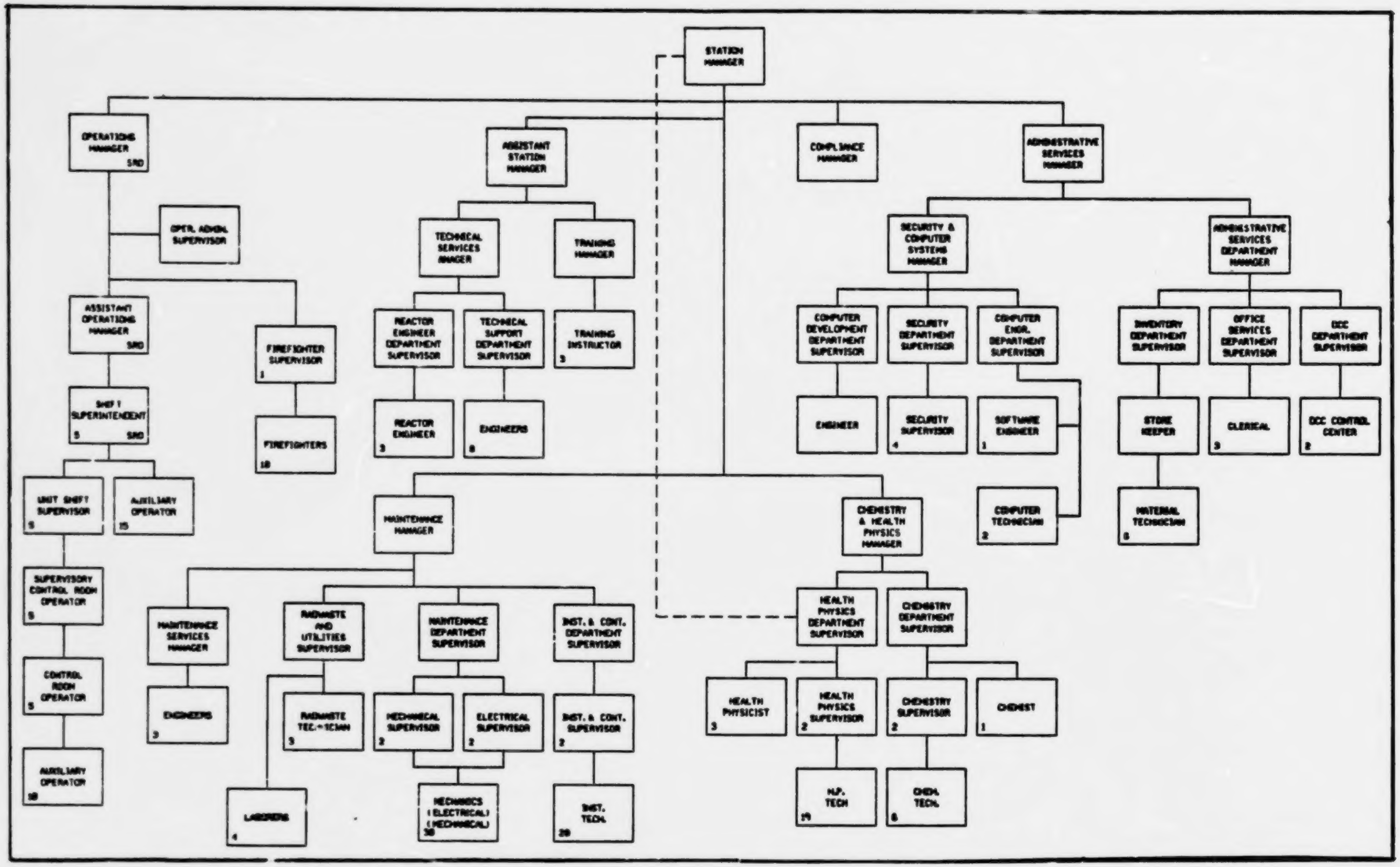
STATION MANAGER
OPERATIONS MANAGER SRO
ASSISTANT STATION MANAGER
COMPLIANCE MANAGER
ADMINISTRATIVE SERVICES MANAGER
OPER. ADMIN. SUPERVISOR
TECHNICAL SERVICES MANAGER
TRAINING MANAGER
SECURITY & COMPUTER SYSTEMS MANAGER
ADMINISTRATIVE SERVICES DEPARTMENT MANAGER
ASSISTANT OPERATIONS MANAGER SRO
FIREFIGHTER SUPERVISOR 1
REACTOR ENGINEER DEPARTMENT SUPERVISOR
TECHNICAL SUPPORT DEPARTMENT SUPERVISOR
TRAINING INSTRUCTOR 3
COMPUTER DEVELOPMENT DEPARTMENT SUPERVISOR
SECURITY DEPARTMENT SUPERVISOR
COMPUTER ENGR. DEPARTMENT SUPERVISOR
INVENTORY DEPARTMENT SUPERVISOR
OFFICE SERVICES DEPARTMENT SUPERVISOR
DCC DEPARTMENT SUPERVISOR
SHIFT SUPERINTENDENT 5 SRO
FIREFIGHTERS 10
REACTOR ENGINEER 3
ENGINEERS 8
ENGINEER
SECURITY SUPERVISOR 4
SOFTWARE ENGINEER 1
STORE KEEPER
CLERICAL 3
DCC CONTROL CENTER 2
UNIT SHIFT SUPERVISOR 5
AUXILIARY OPERATOR 15
MAINTENANCE MANAGER
CHEMISTRY & HEALTH PHYSICS MANAGER
COMPUTER TECHNICIAN 2
MATERIAL TECHNICIAN 6
SUPERVISORY CONTROL ROOM OPERATOR 5
MAINTENANCE SERVICES MANAGER
RADWASTE AND UTILITIES SUPERVISOR
MAINTENANCE DEPARTMENT SUPERVISOR
INST. & CONT. DEPARTMENT SUPERVISOR
HEALTH PHYSICS DEPARTMENT SUPERVISOR
CHEMISTRY DEPARTMENT SUPERVISOR
CONTROL ROOM OPERATOR 5
ENGINEERS 3
RADWASTE TECHNICIAN 5
MECHANICAL SUPERVISOR 2
ELECTRICAL SUPERVISOR 2
INST. & CONT. SUPERVISOR 2
HEALTH PHYSICIST 3
HEALTH PHYSICS SUPERVISOR 2
CHEMISTRY SUPERVISOR 2
CHEMIST 1
AUXILIARY OPERATOR 10
LABORERS 4
MECHANICS (ELECTRICAL) (MECHANICAL) 30
INST. TECH. 20
H.P. TECH 19
CHEM. TECH. 6

Figure 13.2 Seabrook Station organization
Source: FSAR Figure 13.1-5, Amendment 58, April 1986

# 15 ACCIDENT ANALYSES

## 15.4 Reactivity and Power Distribution Anomalies

Generic Letter 85-16, dated August 23, 1985, reported that improvements in analysis methods used for calculating the consequences of steamline breaks have shown that a tradeoff of risks may favor operation of the reactor without a source of highly concentrated borated water. The staff encouraged licensees and applicants to reanalyze their plants to determine their need for highly concentrated boron injection, and subsequently to determine if it would be possible to remove their boron injection tank (BIT). The applicant has completed a reanalysis, and a determination has been made that safer overall operation results if the BIT is not used. The applicant has informed the staff of its intention to delete the BIT from the safety injection (SI) system, has submitted a revised accident description and analysis for FSAR Chapter 15, and has requested resolution of this issue.

The applicant, in letters dated June 13, 1985, April 23, 1986, and May 27, 1986, informed the staff of its intention to delete the BIT from the SI system. The BIT is physically located inside the primary auxiliary building, but is not connected to any plant systems. There are no pipes connecting the BIT, and hence closed valves are not relied on to isolate the BIT.

An analysis of steamline breaks has been performed by Westinghouse which addresses two general categories of steamline breaks using LOFTRAN to compute the thermohydraulic behavior of the reactor (Westinghouse Topical Report WCAP-9226). The first category of steamline break occurs while the reactor is at power before reactor trip. The analysis predicts that tube bundle uncovery will not occur before reactor trip, and, additionally, the point of minimum DNBR (departure from nucleate boiling ratio) also occurs before tube bundle uncovery. Therefore, removal of the BIT does not affect the original analysis as reported in WCAP-9226, and the reported conclusions remain valid.

The second category addresses steamline breaks that occur while the reactor is at hot zero power with the most reactive rod stuck out of the core. This category required a reanalysis of the consequences of the break using LOFTRAN with several assumptions for initial conditions. The reanalysis focused on the behavior of the reactor core and maintained a high heat transfer rate out of the reactor coolant by assuming a delay in steam generator dryout. Additionally, the analysis includes a time delay for core boration based on injection of a volume of water equivalent to an installed BIT filled with water at 0 ppm boron concentration. These assumptions are conservative with respect to the reactor coolant system (RCS), since they maximize cooldown by the faulted steam generator and maximize return to power. Details of this analysis are presented in the revised text and figures for FSAR Chapter 15.

### Evaluation and Conclusions

The staff has reviewed the applicant's submittal and concludes:

(1) The BIT is left in place in the plant. It has been seismically installed, and the applicant states that the quality of the seismic mounting will be maintained to prevent any future safety hazard. All piping connections between the BIT and associated fluid systems have been removed, and the BIT does not rely on closed valves to maintain isolation. This approach is satisfactory.

(2) Review of the applicant's accident analysis indicates that a steamline break with the BIT deleted will affect core return to power and core heating. However, these effects are not severe and are well within established safety limits. The revised Chapter 15 analysis for the FSAR is satisfactory with respect to RCS response.

(3) The FSAR analysis with respect to steamline break consequences outside the RCS pressure boundary does not assume the presence of a BIT, and thus BIT removal has no impact on these analyses.

(4) Deletion of the BIT is approved.

### 15.4.6 Inadvertent Boron Dilution

Dilution of the boric acid concentration within the reactor core adds reactivity to the reactor core. During power operation, inadvertent dilution would lead to actuation of the rod insertion limit alarms if the reactor were in automatic control or to either an alarm or a trip on OTΔT if the reactor were in manual control. Ample time is available to terminate the event following the alarm or trip before the shutdown margin could be lost. During shutdown and hot standby, inadvertent dilution could produce criticality. To protect against inadvertent criticality from boron dilution, Seabrook is designed so that the occurrence of inadvertent dilution would be made known to the operator by alarms indicating deviation from the preset dilution flowrate. In addition, a neutron level alarm is available from the source range channels. This alarm provides a warning to the operator when the neutron count rate increases to 50% above the initial (or base) count rate. At least 15 min would be available to alert the operator following the source range alarm. Redundant source range alarm channels are provided, which are classified as safety-related equipment.

The applicant evaluated boron dilution with the reactor coolant pumps (RCPs) running, during residual heat removal (RHR) system operation without RCPs running, and with the reactor coolant system partially drained for refueling. When the RCPs are not running, the core is more sensitive to boron dilution, since a smaller volume of water is in circulation. Lowering the reactor vessel water level for refueling further decreases the volume of water in circulation through the core.

The applicant utilized a conservatively low circulation volume by considering only the volume of one RHR train, the reactor vessel, and the connecting piping between the vessel and the RHR nozzles. To reduce the rate at which boron dilution could occur while on RHR, administrative controls will be implemented by Technical Specifications to disable the boron thermal regeneration system and one train of the reactor makeup water system.

The staff concludes that the protection from inadvertent boron dilution is consistent with the guidance provided by SRP Section 15.4.6-6 (NUREG-0800) and is, therefore, acceptable.

## 15.8 Anticipated Transients Without Scram

### 15.8.1 Generic Letter 83-28

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant (SNPP) failed to open on an automatic reactor trip signal from the reactor protection system. This incident occurred during plant startup, and the reactor was tripped manually by the operator about 30 sec after the initiation of the automatic trip signal. It has been determined that the failure of the circuit breakers was related to the sticking of the undervoltage trip attachment. On February 22, 1983, an automatic trip occurred during startup of SNPP, Unit 1, as the result of steam generator low-low level. In this case, the reactor was tripped manually by the operator almost coincidentally with the automatic trip. On February 28, 1983, the NRC Executive Director for Operations directed the staff to investigate and report on the generic implications of these occurrences. The results of the staff investigation are reported in NUREG-1000, "Generic Implications of ATWS [Anticipated Transient Without Scram] Events at the Salem Nuclear Power Plant." As a result of this investigation, the Commission requested (by Generic Letter 83-28 dated July 8, 1983) all licensees of operating reactors, applicants for an operating license, and holders of construction permits to respond to certain generic concerns. These concerns are categorized into the following four areas: (1) Post-Trip Review, (2) Equipment Classification and Vendor Interface, (3) Post-Maintenance Testing, and (4) Reactor Trip System Reliability Improvements.

#### 15.8.1.1 Post-Trip Review

The first area, "Post-Trip Review," consists of Item 1.1, "Program Description and Procedure," and Item 1.2, "Data and Information Capability." This evaluation addresses Item 1.1 only. Item 1.2 was evaluated in Section 7.2.4 of SER Supplement No. 4.

The following review guidelines were developed after initial evaluation of several utility responses to Item 1.1 of Generic Letter 83-28 and incorporate the best features of these submittals. Therefore, these review guidelines effectively represent a "good practices" approach to post-trip review. The staff has reviewed the applicant's response to Item 1.1 against these guidelines.

A. The licensee or applicant should have systematic safety assessment procedures established that will ensure that the following restart criteria are met before restart is authorized:

   - The post-trip review team has determined the root cause and sequence of events resulting in the plant trip.

   - Near-term corrective actions have been taken to remedy the cause of the trip.

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  - The post-trip review team has performed an analysis and determined that the major safety systems responded to the event within the specified limits of the primary system parameters.

  - The post-trip review has not resulted in the discovery of a potential safety concern (e.g., the root cause of the event occurs with a frequency significantly larger than expected).

  - If any of the above restart criteria are not met, then an independent assessment of the event is performed by the Plant Operations Review Committee (PORC) or another designated group with similar authority and experience.

B. The responsibilities and authorities of the personnel who will perform the review and analysis should be well defined.

  - The post-trip review team leader should be a member of plant management at the shift supervisor level or above and should hold or should have held a senior reactor operator license on the plant. The team leader should be charged with overall responsibility for directing the post-trip review, including data gathering and data assessment, and he/she should have the necessary authority to obtain all personnel and data needed for the post-trip review.

  - A second person on the review team should be a shift technical advisor (STA) or should hold a relevant engineering degree with special transient analysis training.

  - The team leader and the STA (engineer) should be responsible for concurring on a decision/recommendation to restart the plant. A nonconcurrence from either of these persons should be sufficient to prevent restart until the trip has been reviewed by the PORC or equivalent organization.

C. The licensee or applicant should indicate that the plant response to the trip event will be evaluated and a determination made as to whether the plant response was within acceptable limits. The evaluation should include:

  - A verification of the proper operation of plant systems and equipment by comparison of the pertinent data obtained during the post-trip review to the applicable data provided in the FSAR.

  - An analysis of the sequence of events to verify the proper functioning of safety-related and other important equipment. Where possible, comparisons with previous similar events should be made.

D. The licensee or applicant should have procedures to ensure that all physical evidence necessary for an independent assessment is preserved.

E. Each licensee or applicant should provide in its submittal, copies of the plant procedures that contain the information required in Items A through D. As a minimum, these should include the following:

- the criteria for determining the acceptability of restart
- the qualifications, responsibilities, and authorities of key personnel involved in the post-trip review process
- the methods and criteria for determining whether the plant variables and system responses were within the limits as described in the FSAR
- the criteria for determining the need for an independent review

Evaluation

By letters dated November 4, 1983, March 6, 1986, and June 24, 1986, the applicant provided information regarding its Post-Trip Review Program. The staff has evaluated the applicant's program against the guidelines described above.

A. With regard to the criteria for determining the acceptability of restart, the applicant will cause each reactor trip to be reviewed by the control room personnel after collecting data from the plant records. The control room personnel complete Form OS1000.08A, "Post Reactor Trip/Safety Injection Review," which provides space to record information on plant conditions before the event, the sequence of events, whether or not plant equipment performed as designed, corrective action taken, and whether there are any problems that would prevent the plant from returning to service. The report is signed by the supervisory control room operator or the control room operator.

When Form OS1000.08A is completed by the control room personnel, it is forwarded to the unit shift supervisor for review. The unit shift supervisor verifies that the form is properly completed, evaluates the data, and interviews appropriate personnel to determine the cause of the event and to discuss the sequence of events and the actions taken. When the review is completed, the unit shift supervisor signs Form OS1000.08A and forwards it as part of the post-trip data package to the STA/shift supervisor.

The STA/shift supervisor reviews the post-trip package, evaluates the corrective actions that have been or need to be taken before startup, and ensures that the cause of the event has been properly identified and that all equipment and safety systems performed as designed. The STA/shift supervisor then signs Form OS1000.08A and forwards the post-trip package together with a recommendation regarding whether or not the unit may be restarted to the station manager, the assistant station manager, or the operations manager.

If the cause of the trip has not been clearly determined or if there is a question regarding the proper performance of equipment and/or systems during the event, then an investigation must be conducted by the Station Operations Review Committee (SORC) before startup. When so indicated, the SORC performs a complete investigation of the event and makes a complete report to the station manager.

On review of the post-trip package forwarded by the STA/shift supervisor, and after review by the SORC if indicated, the station manager, the assistant station manager, or the operations manager may authorize restart.

The staff finds that the applicant's criteria for determining the acceptability for restart are in conformance with the guidelines described above and, therefore, are acceptable.

B. As summarized in Item A, the responsibilities and authorities of personnel performing the post-trip review are well defined. The staff finds that the applicant's chain of command for responsibility for post-trip review is in conformance with the above guidelines and is acceptable.

C. The applicant has described the information that will be collected and evaluated during the performance of the post-trip review. The information will be analyzed for protection system and overall plant response and will be compared with expected plant response as described in the plant Technical Specifications and FSAR. The staff finds that the applicant's plans for post-trip analysis and evaluation are in conformance with the above guidelines and are, therefore, acceptable.

D. As noted in Item A, the applicant has stated that if the cause of the reactor trip is unknown, or if safety-related equipment did not function properly, the trip must be reviewed by the SORC. The applicant has stated that review reports and supporting documentation will be retained for the life of the plant. The staff finds that the applicant's criteria for independent assessment of unscheduled reactor trips and for preservation of documentation relating to unscheduled trips are in conformance with the above guidelines and are, therefore, acceptable.

E. Instructions on performing post-trip reviews are contained in Station Operating Procedure OS1000.08, "Post-Trip Review." The staff has reviewed the procedure and concludes that it is acceptable.

Conclusion

On the basis of its review of the applicant's program description for post-trip review and Station Operating Procedure OS1000.08, "Post-Trip Review," the staff concludes that the applicant's post-trip review program and procedure are acceptable.

#### 15.8.1.2 Equipment Classification and Vendor interface

Items 2.1 and 2.2 of Generic Letter 83-28 are discussed in Section 7.2.4 of SER Supplement No. 4.

#### 15.8.1.3 Post-Maintenance Testing

Items 3.1.3 and 3.2.3 of Generic Letter 83-28 are discussed in Section 7.2.4 of SER Supplement No. 4.

#### 15.8.1.4 Reactor Trip System Reliability Improvements

Generic Letter 83-28 addressed intermediate-term actions to be taken by licensees and applicants to ensure that a comprehensive program of preventive maintenance

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and surveillance testing is implemented for the reactor trip breakers (RTBs) in pressurized-water reactors. In particular, Item 4.1 of the letter required licensees and applicants to verify that all vendor-recommended RTB modifications have been implemented. Item 4.2 required them to submit a description of their preventive maintenance and surveillance program to ensure reliable RTB operation. The description of the submitted program was to include the following:

(1) Item 4.1--all vendor-recommended RTB modifications to verify that either each modification has, in fact, been implemented or a written evaluation of the technical reasons for not implementing a modification exists

(2) Item 4.2.1--a planned program of periodic maintenance, including lubrication, housekeeping, and other actions recommended by the equipment supplier

(3) Item 4.2.2--trending of parameters affecting operation and measured during testing to forecast degradation of operation

The applicant responded to the generic letter on November 4, 1983, and August 5, 1985. The adequacy of the applicant's responses and of the preventive maintenance and surveillance programs for RTBs is evaluated below.

(1) Periodic Maintenance Program

The primary source for periodic maintenance program criteria is Westinghouse Maintenance Program Manual for DS-416 Reactor Trip Circuit Breakers, Revision 0. This document was prepared for the Westinghouse Owners Group and is the breaker manufacturer's recommended maintenance program for the DS-416 breaker. It provides specific directions with regard to schedule, inspection and testing, cleaning, lubrication, corrective maintenance, and record keeping. The staff reviewed the document to identify those items that contribute to breaker trip reliability consistent with the generic letter. Those items identified for maintenance at 6-month intervals (or when 500 breaker operations have been counted, whichever comes first) that should be included in the applicant's RTB maintenance program are

(a) general inspection to include checking of breaker's cleanliness, all bolts and nuts, pole bases, arc chutes, insulating link, wiring, and auxiliary switches

(b) inspection of retaining rings, including those on the undervoltage trip attachment (UVTA)

(c) inspection of arcing and main contacts as specified by the Westinghouse manual

(d) UVTA check as specified by the Westinghouse manual, including replacement of UVTA if dropout voltage is greater than 60% or less than 30% of rated UVTA coil voltage

(e) shunt trip attachment check as specified by the Westinghouse manual

(f) lubrication as specified by the Westinghouse manual

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(g) functional check of the breaker's operation before it is returned to service

The applicant's RTB periodic maintenance should also include, on a refueling interval basis,

(a) precleaning insulation resistance measurement and recording

(b) RTB dusting and cleaning

(c) postcleaning insulation resistance measurement and recording as specified by the Westinghouse manual

(d) inspection of main and secondary disconnecting contacts, bolt tightness, secondary wiring, mechanical parts, cell switches, instruments, relays, and other panel-mounted devices

(e) UVTA trip force and breaker load check as specified by the Westinghouse manual

(f) measurement and recording of RTB response time for the undervoltage trip

(g) functional test of the breaker before it is returned to service as specified by the Westinghouse manual

(2) Trending of Parameters

Item 4.2.2 of Generic Letter 83-28 specifies that the preventive maintenance and surveillance program is to include trending of parameters affecting operation and measured during testing to forecast degradation of operation. The parameters measured during the maintenance program described above that are applicable for trending are UVTA dropout voltage, trip force, response time for undervoltage trip, and breaker insulation resistance. The staff position is that the above parameters are acceptable for trending to forecast breaker operation degradation or failure. If subsequent experience indicates that any of these parameters are not useful as a tool to anticipate failures or degradation, the licensee or applicant may, with justification and NRC approval, elect to remove that parameter from those to be tracked.

The staffs' evaluation of the applicant's position on Items 4.1, 4.2.1, 4.2.2, and 4.3 of Generic Letter 83-28 follows:

(1) Item 4.1

The applicant has confirmed that all vendor-recommended equipment modifications have been completed. The staff finds the applicant's position on Item 4.1 acceptable.

(2) Item 4.2.1

The applicant has confirmed that the periodic maintenance program for RTBs will include those items listed above under "Periodic Maintenance Program."

However, the applicant plans to perform preventive maintenance during each refueling outage or after 500 breaker operations, whichever comes first. The staff finds the applicant's position on Item 4.2.1 acceptable. Acceptance of the applicant's extended maintenance interval is based on the vendor recommendation that maintenance on RTBs located in mild environments should be performed at refueling intervals. The vendor recommendation that RTBs located in harsh environments or experiencing severe load conditions be maintained more frequently is not applicable to these RTBs because of their location in a mild environment and reduced service duty at Seabrook.

(3) Item 4.2.2

The applicant has stated that trend analysis on the parameters listed above under "Trending of Parameters" will be performed at Seabrook. The applicant has identified the organization that will perform trend analysis, how often it will be performed, and how the information derived from the analysis will be used to affect periodic maintenance. The staff finds the applicant's position on Item 4.2.2 acceptable.

(4) Item 4.3

The applicant has included in the Technical Specifications elements that meet the requirements of Generic Letter 85-09 and Subitem 13 of Generic Letter 83-28, Item 4.3. The staff has reviewed these elements and finds them acceptable.

The staff also evaluated Item 4.3 in Section 7.2.4 of SER Supplement No. 4.

Conclusions

On the basis of a review of the applicant's responses, the staff finds the applicant's position on Items 4.1, 4.2.1, 4.2.2, and 4.3 of Generic Letter 83-28 acceptable.

## 15.9 TMI Action Plan Requirements

### 15.9.9 II.K.3.5 Automatic Trip of RCPs During a LOCA

In a letter from H. L. Thompson, NRC, to all applicants and licensees with Westinghouse-designed nuclear steam supply systems dated June 28, 1985, the staff reported that the information provided by the Westinghouse Owners Group (WOG) in support of alternative reactor coolant pump (RCP) trip was acceptable on a generic basis. The review noted that a number of considerations were assigned plant-specific status. Accordingly, the staff requested, in the June 28, 1985, letter, that operating reactor applicants and licensees select and implement an appropriate RCP trip criterion based on the WOG methodology (Eisenhut, February 8, 1983).

The applicant provided a response to this request by letter dated March 31, 1986, which was reviewed by the staff, and which resulted in preliminary comments and questions (Berlinger, April 10, 1986). This information was discussed with the applicant (Berlinger, May 16, 1986; letter to the applicant dated May 20, 1986) and was used in a final applicant response (letter dated May 27, 1986).

The applicant selected a subcooling margin of 30°F, independent of containment conditions, as the criterion for RCP trip. The selection was justified by stating that derivation of the Seabrook RCP trip parameter was in accordance with WOG generic guidelines, and that the final subcooling value met all WOG generic requirements. (Note the subcooling option was previously identified by the staff as generically acceptable). The applicant arrived at this selection by evaluating the three criteria recommended by the WOG and concluded that subcooling more consistently represented the reactor coolant system (RCS) condition for Seabrook, and that it provided sufficient differentiation between a loss-of-coolant accident and steam generator tube rupture (SGTR) to serve as an RCP trip criterion. The applicant further concluded that the parameter is readily available to the operator, no operator calculations are required for its application, it is little influenced by the instrumentation environment, and the selected value used for RCP trip is sufficiently high that environmental conditions need not be considered by the operator. The applicant further stated that full consideration was given to the information contained in the WOG guidelines pertinent to RCP trip criteria, and the information is also used during operator training so that the operator will be fully aware of the need for RCP operations.

The applicant further stated:

> The Setpoint Study calculations were performed using pressure temperature instrumentation with the largest calculated errors. By using this approach, the operator is not restricted to a specific type of instrument for determination of RCP trip. As an example, determination of subcooling could be made by:
>
> - direct reading from Subcooling Margin Monitor
> - direct reading from Main Plant Computer System, and
> - manual calculation using steam tables and any combination of
>
>   1) MCB* pressure indication (Pressurizer or RCS pressure), and
>   2) MCB temperature (incore thermocouples or RCS loop wide range RTDs**).

The referenced calculational procedure leads to subcooling margin results that are reasonable, and the flexible approach provides the operator with options that can be utilized if an instrument is lost. Discussions between the applicant and the staff revealed a clear applicant understanding of the methodology and background considerations pertinent to the determination of subcooling under all reasonably expected plant conditions. For example, the applicant considered uncertainties associated with normal and adverse environmental conditions and selected a subcooling margin that was determined to be sufficiently high so that variations due to an adverse environmental condition are covered and do not have to be considered by the operator.

Studies were reported in which affected regions have been defined in the vicinity of high-energy lines. These have established that, at most, only one

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*Main control board.

**Resistance temperature detectors.

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instrument can be affected in a redundant system. Automatic selection of sensor readings and operator training address the possibility of erroneous instrumentation.

The applicant has addressed RCP operational concerns, including the effect of containment isolation. The RCP seals are cooled by either seal injection via the chemical volume and control system or thermal barrier cooling via the component cooling water (CCW) system. Containment isolation is stated to only affect discharge from the seals, which is rerouted to the pressurizer relief tank. Both seal flow and CCW flow to the RCPs continue. Consideration was also given to events that are beyond the design basis. For example, the applicant has considered plant behavior and operator response if both CCW cooling and RCP seal injection are lost, including both loss of all ac power and continuation of ac power situations. In the latter situation, the unique system used for thermal barrier coolers at Seabrook contributes to a slow thermal response of the RCP seals because water will be circulated between the referenced system and the thermal barrier heat exchangers, thus contributing a significant thermal mass.

With respect to operational considerations, RCPs are normally not run for more than 2 min without motor cooling. There are additionally a number of trip parameters, such as bearing temperatures, seal water return rate, and seal water pressure differential, which must be met for normal RCP operation. There are tight temperature rate limitations on reinitiation of RCP operation following a loss of all seal cooling. These items would be applied to most circumstances that could exist in the plant. An exception is inadequate core cooling. Here, the RCPs would be restarted in accord with information provided in the WOG Emergency Procedures Guidelines, Revision 1, which Seabrook follows in general. Staff discussion of these and similar points with the applicant clearly established that a number of plant procedures apply to the points identified by the staff, that the personnel representing Seabrook were familiar with these procedures and the underlying need, and that the necessary precautions were reflected in the procedures and understanding.

The major components associated with RCP trip were identified by the applicant, and their location was established as outside containment. All equipment is located in electrical equipment areas that do not have high-energy lines.

In the event of unsuccessful operator attempts to trip RCPs from the control board, there are alternative techniques that would be applied. For example, under normal circumstances one could trip the breakers by physically walking to the breaker location. One could also shed the bus that provides power to the RCPs. (There is no safety-related equipment on the bus, which also provides power to circulating water pumps and some nonvital motor control centers.) Backup procedures to accomplish these actions are not provided. Such actions are covered in operator training and are considered by the applicant to be a normal response that follows from such training, which provides an emphasis on operator understanding of plant response and the need for taking certain mitigative actions to plant conditions. This approach is acceptable.

Information exchange between the staff and the applicant identified that the subcooling margin utilized for RCP trip is not an absolute, and other plant conditions may affect RCP trip. Unavailability of makeup water to the RCS

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represents such a case, and Seabrook operators would run RCPs as long as it is reasonable to extend core cooling beyond what would be obtained if the RCPs were tripped under these unique and unexpected conditions. (Such actions are taken under conditions that are unlikely, that are beyond the design basis, and that are beyond conditions reported in the FSAR.) The staff has not reviewed the tradeoffs between operating RCPs if there is no ability to provide makeup water to the RCS as contrasted to tripping RCPs. There are logical arguments to support both positions. The staff will address this generically. Since many Westinghouse plants probably have incorporated this WOG-provided guidance into their emergency procedures, the staff currently accepts this approach unless there is a clear need for its rejection. No such need is currently apparent.

The staff finds the applicant's submittal pertinent to RCP trip acceptable.

### 15.9.15 III.D.1.1 Integrity of Systems Outside Containment Likely To Contain Radioactive Material

When the SER was issued, the applicant had committed to submit 4 months before fuel load a description of the program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a transient or accident. This was identified as Confirmatory Issue No. 41.

The program was described in PSNH letters SBN-1069 and SBN-1105 dated May 27, 1986, and June 11, 1986. These two letters provide a summary description of the program. The principal elements of the program are:

(1) Immediate steps will be taken to reduce leakage to as low as practicable levels.

(2) Leak rate measurements have been made, and additional measurements will be made during preoperational testing.

(3) The leakage reduction program will be continued through the life of the plant.

(4) The systems included in the program are

    (a) residual heat removal
    (b) containment spray recirculation
    (c) charging
    (d) safety injection
    (e) primary coolant sampling (including the postaccident sampling system)
    (f) hydrogen detection

(5) Systems excluded from the program are

    (a) hydrogen recombiners (inside containment)
    (b) waste gas system (not required for accident control)

(6) Helium leak testing will be used for testing the gaseous systems.

(7) Action has been taken to reduce leakage potential from design and operator deficiencies as addressed in a generic letter dated October 17, 1979.

The staff has reviewed this program description and concluded that it meets regulatory requirements and, therefore, is acceptable.

The applicant has not yet submitted the results of leak rate measurements to the staff. This is required by NUREG-0737 before issuance of a full-power license. The applicant will be required to submit these data for staff review before 5% power is exceeded, and the license will be conditioned to state:

> Prior to proceeding above 5% of rated power, the applicant shall submit the results of leak rate measurements which demonstrate that its leakage reduction program has been sucessfully implemented.

By letter dated June 20, 1986, the applicant committed to submit these data to the staff before initial criticality.

## 16 TECHNICAL SPECIFICATIONS

During the preparation of the Technical Specifications for Seabrook Station, Unit 1, the applicant proposed a Technical Specification Improvement Program. The results of the staff's review of several items in that program were reported in a letter to the applicant on May 20, 1986. The staff concluded that certain Technical Specification requirements could be eliminated from the Technical Specifications if the applicant (1) developed acceptable procedures for control of operations, (2) developed acceptable procedures for controlling changes to those procedures, and (3) identified in the FSAR and the Offsite Dose Calculation Manual (ODCM) the operations that will be subjected to these controls.

By letter of June 17, 1986, the applicant transmitted the Seabrook ODCM. Included in the ODCM are the following tables:

(1) Radioactive Liquid Waste Sampling and Analysis Program
(2) Radioactive Gaseous Waste Sampling and Analysis Program
(3) Radiological Environmental Monitoring Program
(4) Detection Capabilities for Environmental Sample Analysis
(5) Reporting Levels for Radioactivity Concentrations in Environmental Samples

By letter of June 23, 1986, the applicant transmitted information for incorporation in the FSAR that would be subjected to the alternative controls. This information is as follows:

(1) reactor trip system instrumentation response times
(2) engineered safety feature activation system instrumentation response times
(3) loose part detection system
(4) reactor vessel material irradiation specimens
(5) snubbers--inservice inspection program
(6) containment isolation valves
(7) fire hose stations
(8) yard fire hydrants and hydrant hose stations
(9) containment penetration conductor overcurrent protection
(10 motor-operated valves thermal overload protection

The staff has determined that this list of items is consistent with its approvals for removal of items from the Technical Specifications.

In the June 23, 1986, letter, the applicant also included the administrative controls for the Seabrook Station Technical Specification Improvement Program.

The staff finds that the applicant has included the items removed from the Technical Specifications in the ODCM and FSAR and has provided the requisite controls. The staff, therefore, concludes that the portions of the Technical Specification Improvement Program found acceptable in its May 20, 1986, letter, are appropriately documented and acceptable for implementation.

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# 17 QUALITY ASSURANCE

## 17.2 Organization

As a result of the applicant's submittals through FSAR Amendment 58, there were several organizational changes that affected the staff's previous SER organizational description for the operation of Seabrook Station. Therefore, the following description supersedes that in SER Section 17.2 and SER Figure 17.1 is replaced by Figure 17.1 in this supplement.

The organization responsible for the operation of Seabrook Station and for the establishment and execution of the operational quality assurance (QA) program is shown in Figure 17.1. The Public Service Company of New Hampshire (PSNH) President and Chief Executive Officer (CEO) has delegated to the New Hampshire Yankee (NHY) President and CEO, a division within PSNH, the direct responsibility for operation, maintenance, modification, and refueling of Seabrook Units 1 and 2. The NHY Vice President-Nuclear Production reports through the NHY Senior Vice President to the NHY President and is responsible for the operation and operational support of Seabrook Units 1 and 2. The Seabrook Station Manager and other support groups report to the NHY Vice President-Nuclear Production. The Vice President and Director of Quality Programs reports to the NHY Senior Vice President and is in charge of the Nuclear Quality Group, which consists of a Quality Assurance Section, an Audit and Evaluation Section, and a Quality Control Section.

The Vice President and Director of Quality Programs has been delegated the authority for establishing QA program requirements, verifying implementation, and measuring the overall effectiveness of the QA program. The Vice President and Director of Quality Programs and his staff (which currently consists of 27 persons) have the responsibility and authority to stop unsatisfactory work and control further processing, delivery, or installation of nonconforming material.

The QA organization has the authority to (1) identify quality problems; (2) initiate, recommend, or provide solutions through designated channels; (3) verify implementation of solutions; and (4) stop unsatisfactory work and control further processing, delivery, or installation of nonconforming items. The QA organization is responsible for (1) reviewing and concurring with documents affecting safety; (2) verifying inplant activities by surveillance inspections and examinations; (3) evaluating suppliers before contracts are awarded; (4) inspecting suppliers' facilities; (5) ensuring that personnel qualifications are current and applicable to the work being performed; (6) ensuring that corrective actions are effective and accomplished in a timely manner; and (7) conducting internal audits of maintenance, modification, and operations activities and external audits of suppliers' activities.

The Seabrook Station Manager reports to the Vice President-Nuclear Production and is responsible for (1) ensuring the safe, reliable, and efficient operation of the plant and (2) ensuring that quality-affecting activities are conducted

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in accordance with the QA program. Disputes on any QA matter that arise between QA/quality control and other departments are resolved by the management of the involved organizations or, if necessary, with the NHY Senior Vice President.

The staff has reviewed the new organization and concludes that the organizations and persons performing QA functions appear to have the required independence and authority to effectively carry out the QA program without undue influence from those directly responsible for costs and schedules.

### 17.3 Quality Assurance Program

The scope of the operational QA program was shown in the SER as Outstanding Issue No. 18. Supplement No. 3 gives the resolution of this issue. After Supplement No. 3 was issued, discrepancies in subsequent FSAR amendments again brought into question the scope of the operational QA program. A request for additional information in this regard was sent to the applicant by letter dated December 24, 1985. By letter dated May 17, 1986, the applicant responded to the staff's request and resolved the discrepancies by clarifying the applicant's position so that the scope of the operational QA program is acceptable. The staff's evaluation of the applicant's QA program as set forth in Supplement No. 3 remains valid.

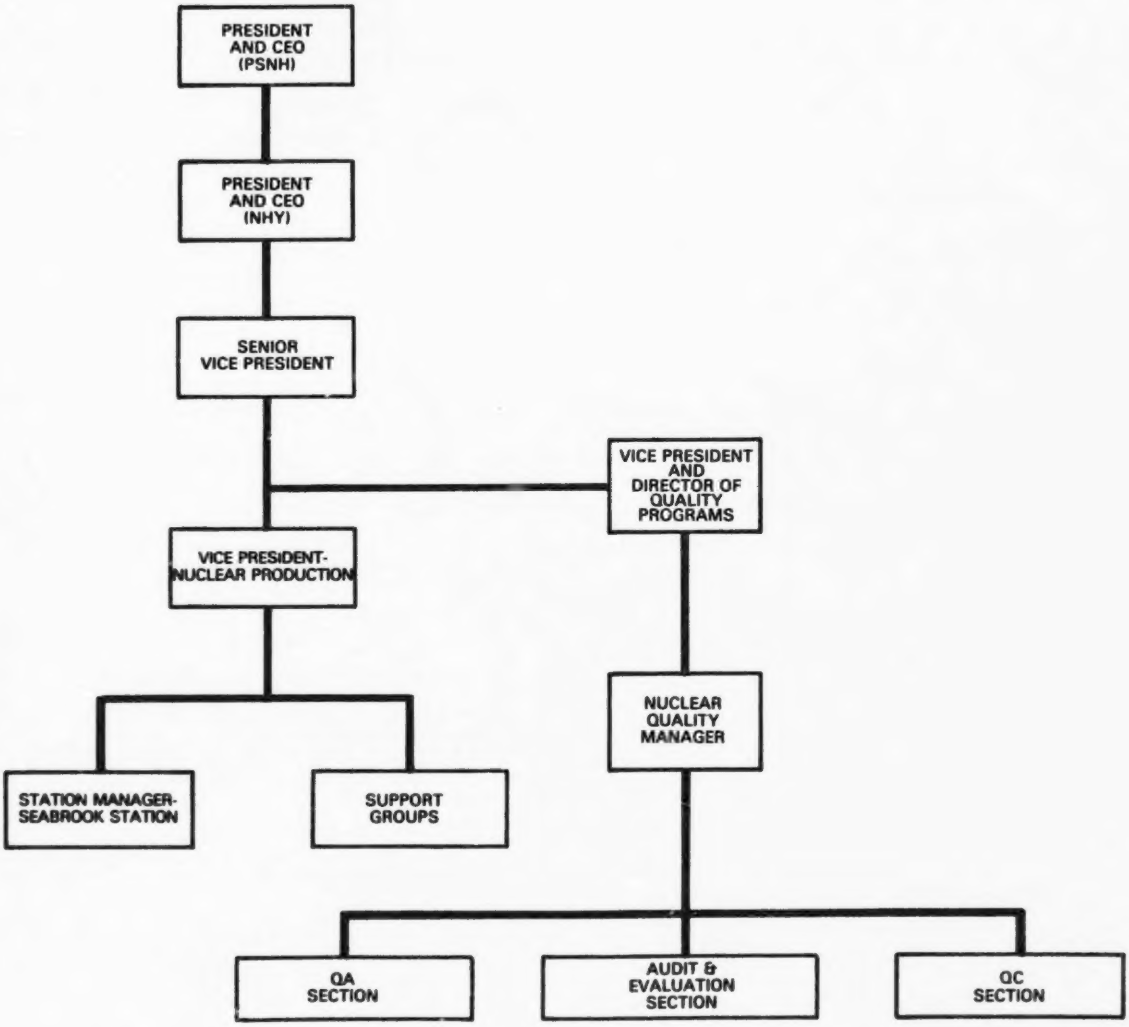
PRESIDENT AND CEO (PSNH)
PRESIDENT AND CEO (NHY)
SENIOR VICE PRESIDENT
VICE PRESIDENT AND DIRECTOR OF QUALITY PROGRAMS
VICE PRESIDENT-NUCLEAR PRODUCTION
NUCLEAR QUALITY MANAGER
STATION MANAGER-SEABROOK STATION
SUPPORT GROUPS
QA SECTION
AUDIT & EVALUATION SECTION
QC SECTION

Figure 17.1 Operations quality assurance organization
Source: FSAR Figure 17.2-1

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# APPENDIX A

## CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW

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| August 5, 1985 | Letter from applicant transmitting additional information regarding Generic Letter 83-28, Item 4.2.1 (Periodic Maintenance Program for Reactor Trip Breakers) and 4.2.2 (Trending of Reactor Trip Breaker Parameters To Forecast Degradation of Operability). |
| November 5-8, 1985 | Representatives from NRC and PSNH met at the Seabrook site to discuss the Seismic Qualification Review and the Pump and Valve Operability Review Teams' audit activities. (Summary issued December 17, 1985.) |
| December 20, 1985 | Letter from applicant concerning preservice and inservice inspection program (SER Outstanding Issue No. 4 and Licensing Condition No. 4). |
| March 3, 1986 | Letter from applicant transmitting the Seabrook Station Offsite Dose Calculation Manual. |
| March 6, 1986 | Letter from applicant transmitting additional information regarding Generic Letter 83-28, Item 1.2, "Post-Trip Review (Data and Information Capability)." |
| March 31, 1986 | Letter from applicant responding to Generic Letter 85-21, "Implementation of TMI Action Item II.K.3.5, 'Automatic Trip of Reactor Coolant Pumps.'" |
| April 15, 1986 | Representatives from NRC and PSNH met at Seabrook site for a specific demonstration to determine the effectiveness of the applicant's ultrasonic examinations on statically cast stainless steel. (Trip report, dated May 7, 1986, issued.) |
| April 29, 1986 | Letter from applicant transmitting a response to integrated design inspection. |
| April 29, 1986 | Letter from applicant concerning Voltage Regulatory Study. |
| May 2, 1986 | Letter from applicant concerning Seabrook proof-and-review Technical Specifications. |
| May 2, 1986 | Letter from applicant transmitting a response to Generic Letter 86-04, "Policy Statement on Engineering Expertise on Shift." |

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| May 7, 1986 | Letter from applicant concerning staff requests for additional information on Regulatory Guide 1.8, seismic and safety classifications, revetment surveillance, Cable Tray Support Qualification Program Report, station manager approval authority, and the Independent Safety Engineering Group organization. |
| May 7, 1986 | Letter from applicant requesting renewal of Construction Permit CPPR-135 and extension of construction completion date. |
| May 7, 1986 | Letter from applicant concerning containment isolation system/10 CFR 50, Appendix J, Type C leak rate testing. |
| May 8, 1986 | Letter from applicant transmitting a response to request for additional information (RAI) regarding risk-based Technical Specification changes. |
| May 9, 1986 | Letter from applicant concerning meteorological measurements program. |
| May 10, 1986 | Letter from applicant concerning Seabrook operator training program. |
| May 10, 1986 | Letter from applicant responding to NRC request for additional information from Instrumentation and Control Systems Branch. |
| May 12, 1986 | Letter from applicant concerning availability of emergency lighting during station blackout. |
| May 13, 1986 | Letter from applicant responding to RAI 410.58 regarding multi-high impedance fault. |
| May 13, 1986 | Letter from applicant responding to staff request for additional information regarding COP system isolation valves. |
| May 13-15, 1986 | Representatives from PSHN-New Hampshire Yankee Division met with NRC staff at Seabrook Project Office in Bethesda, Maryland, to have applicant address the staff comments and question on the pump and valve inservice testing program. (Various meeting summaries will be issued.) |
| May 15, 1986 | Letter from applicant concerning preservice inspection program (SER Outstanding Issue No. 4) regarding ultrasonic examination of cast stainless steel. |
| May 17, 1986 | Letter from applicant transmitting additional comments on Seabrook Technical Specifications. |
| May 17, 1986 | Letter from applicant responding to NRC/Lawrence Livermore National Laboratory draft review of Seabrook Station Probabilistic Safety Assessment. |

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| May 17, 1986 | Letter from applicant responding to staff questions on Seabrook's operational quality assurance program. |
| May 17, 1986 | Letter from applicant responding to staff questions on Seabrook Technical Specifications. |
| May 20, 1986 | Letter from applicant concerning "Radiological Emergency Response Plan, State of New Hampshire and Affected New Hampshire Communities: Additional Information." |
| May 20, 1986 | Letter from applicant concerning NUREG-0737, Item II.F.1, noble gas effluent monitoring. |
| May 20, 1986 | Letter to applicant concerning conference call with personnel representing Seabrook Station on April 10, 1986. |
| May 20, 1986 | Letter from applicant transmitting additional information on isolation cabinet MM-CP-470 (SER Confirmatory Issue No. 25). |
| May 20, 1986 | Letter to applicant concerning Seabrook Station Technical Specification Improvement Program. |
| May 20, 1986 | Letter from applicant transmitting Supplement No. 1 to Amendment 57 to license application, dated March 30, 1973, and requesting partial transfer of Construction Permits CPPR-135 and CPPR-136. The letter transmits the Agreement of Purchase and Sale, dated April 7, 1986, between Fitchburg Gas and Electric Light Company and Eastern Utilities Associates. |
| May 21, 1986 | Letter from applicant concerning application for amendment to construction permits regarding exemption from 10 CFR 50, Appendix J, III.D.2.(b)(ii). |
| May 23, 1986 | Letter from applicant responding to request for additional information on SER Confirmatory Issue No. 25. |
| May 27, 1986 | Letter from applicant concerning Confirmatory Issue No. 41--Systems outside containment containing radioactive material--NUREG-0737, Item III.D.1.1. |
| May 27, 1986 | Letter from applicant responding to NRC request for additional information regarding deletion of the boron injection tank. |
| May 27, 1986 | Letter from applicant concerning reactor coolant pump trip--TMI Action Item II.K.3.5. |
| May 28, 1986 | Letter from applicant concerning preservice inspection program (SER Outstanding Issue No. 4). |
| May 28, 1986 | Letter from applicant responding to request for additional information on SER Confirmatory Issue No. 25. |

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| May 29, 1986 | Letter from applicant responding to SER Confirmatory Issue No. 40 regarding inadvertent boron dilution. |
| May 29, 1986 | Letter from applicant responding to NRC requests for additional information on inadequate core cooling, non-nuclear safety systems and components, mobile waste services, initial test program, and tornado missile analysis for the diesel generator exhaust stacks. |
| May 30, 1986 | Letter from applicant concerning accident monitoring instrumentation review and compliance with Regulatory Guide 1.97, Revision 3. |
| May 30, 1986 | Letter from applicant concerning Confirmatory Issue No. 1 regarding exclusion agreements. |
| June 1, 1986 | Letter from applicant concerning natural circulation tests--SER Section 15.4.7.5 (SER License Condition No. 5). |
| June 2, 1986 | Letter from applicant transmitting Supplement No. 2 to Final Safety Analysis Report (FSAR) Amendment 57. |
| June 3, 1986 | Letter from applicant concerning level measurement error (SER Outstanding Issue No. 10). |
| June 4, 1986 | Letter from applicant concerning NUREG-0612, "Control of Heavy Loads," regarding modification to cranes. |
| June 4, 1986 | Letter from applicant concerning NUREG-0612, "Control of Heavy Loads," regarding revision to heavy loads report. |
| June 4, 1986 | Letter from applicant responding to request for additional information regarding COP system isolation valves. |
| June 5, 1986 | Letter from applicant concerning potential superheating steam conditions resulting from main steamline breaks. |
| June 5, 1986 | Letter from applicant concerning use of temporary jumpers. |
| June 6, 1986 | Letter from applicant concerning environmentally qualified accident monitoring equipment. |
| June 6, 1986 | Letter from applicant forwarding Revision 1 to Radiological Emergency Response Plans. |
| June 9, 1986 | Letter from applicant concerning turbine maintenance program. |
| June 10, 1986 | Letter to applicant forwarding Amendment 7 to Construction Permits CPPR-135 and CPPR-136 granting partial exemptions from requirements of General Design Criterion 4 of Appendix A to 10 CFR 50. |

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| June 10, 1986 | Letter from applicant concerning electrical separation criteria and commitments to Regulatory Guide 1.75. |
| June 11, 1986 | Letter to applicant forwarding Supplement No. 4. |
| June 11, 1986 | Letter from applicant forwarding revised description of surveillance program. |
| June 11, 1986 | Letter from applicant concerning SER Confirmatory Item No. 25. |
| June 11, 1986 | Letter from applicant forwarding revision to Section 9.5.1 of the FSAR. |
| June 11, 1986 | Letter from applicant concerning interpretation of Section III.D.1 of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code regarding component and piping support. |
| June 11, 1986 | Letter from applicant responding to staff's request for additional information. |
| June 12, 1986 | Representatives from NRC and PSNH met in Bethesda, Maryland, to discuss fire protection program. |
| June 13, 1986 | Letter to applicant forwarding environmental assessment and finding of no significant impact regarding its request for extension of construction completion date. |
| June 13, 1986 | Letter from applicant forwarding "Seabrook Station Evaluation Time Estimates and Traffic Management Plan Updating." |
| June 13, 1986 | Letter from applicant concerning seismic and dynamic qualification. |
| June 13, 1986 | Letter from applicant concerning electrical code and raceway separation criteria. |
| June 13, 1986 | Letter from applicant concerning deviation from 10 CFR 50, Appendix R. |
| June 13, 1986 | Letter from applicant concerning open items regarding diesel generator control. |
| June 13, 1986 | Letter from applicant forwarding revised preservice inspection program relief requests. |
| June 16, 1986 | Letter from applicant concerning qualifications of isolators in ex-core neutron detector equipment. |
| June 16, 1986 | Letter from applicant concerning high containment pressure alarms. |

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| June 16, 1986 | Letter from applicant forwarding Revision 6 to Plant Security Plan. |
| June 17, 1986 | Letter from applicant concerning closure of feedwater isolation valves. |
| June 17, 1986 | Letter from applicant concerning system interfaces, spill prevention control, and quality assurance. |
| June 17, 1986 | Letter from applicant forwarding revised Offsite Dose Calculation Manual (ODCM). |
| June 17, 1986 | Letter from applicant concerning mean probability value of tornado missile strike. |
| June 18, 1986 | Letter to applicant transmitting final draft Technical Specifications for Seabrook Unit 1. |
| June 18, 1986 | Letter from applicant concerning systems outside containment. |
| June 18, 1986 | Letter from applicant concerning inservice testing report regarding pumps and valves. |
| June 20, 1986 | Letter from applicant concerning certification of final draft Technical Specifications. |
| June 20, 1986 | Letter from applicant concerning status of cable tray qualification program. |
| June 20, 1986 | Letter from applicant concerning limitorque actuators. |
| June 20, 1986 | Letter from applicant concerning error calculations in emergency operating procedures. |
| June 20, 1986 | Letter from applicant concerning systems outside containment. |
| June 20, 1986 | Letter from applicant concerning status of SER unresolved licensing issues. |
| June 23, 1986 | Letter from applicant forwarding "Reactor Containment Building Integrated Leak Rate Test." |
| June 23, 1986 | Letter from applicant concerning Seabrook Station Technical Specification Improvement Program. |
| June 23, 1986 | Letter from applicant concerning inservice testing (IST) of pumps and valves (SER Outstanding Issue No. 4). |
| June 23, 1986 | Letter from applicant concerning TMI Action Plan Item II.K.3.17 and report on outages of emergency core cooling systems. |
| June 23, 1986 | Letter to applicant concerning approved security plans for Seabrook Unit 1. |

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| June 24, 1986 | Letter from applicant concerning completion of seismic qualification and pump and valve operability programs. |
| June 24, 1986 | Letter from applicant concerning additional information regarding Generic Letter 83-28, Item 1.1 (Post-Trip Review Program Description and Procedure). |
| June 25, 1986 | Letter from applicant concerning auxiliary feedwater system Technical Specifications. |
| June 25, 1986 | Letter from applicant concerning inservice testing of pumps and valves (SER Outstanding Issue No. 4), Relief Request No. 46. |
| June 25, 1986 | Letter from applicant requesting full 40-year-term operating license. |
| June 26, 1986 | Letter from applicant concerning comments to draft license for Seabrook Unit 1. |
| June 26, 1986 | Letter from applicant responding to NRC requests for additional information on the radiation data management system, atmospheric steam dump valves, station service water, inadequate core cooling instrumentation, and open items from the Electrical Instrumentation and Control Systems Branch site audit. |
| June 26, 1986 | Letter to applicant concerning changes to the Seabrook final draft Technical Specifications. |
| June 27, 1986 | Letter from applicant concerning completion of seismic qualification and pump and valve operability programs and Supplement No. 4, Section 3.10.1.3. |
| June 27, 1986 | Letter from applicant transmitting additional information regarding Generic Letter 83-28. |
| July 1, 1986 | Letter from applicant concerning revised ODCM. |
| July 1, 1986 | Letter from applicant concerning completion of seismic qualification and pump and valve operability programs, Supplement No. 4, Section 3.10.2.3. |
| July 3, 1986 | Letter from applicant requesting issuance of an operating license for Seabrook Unit 1 by June 20, 1986. |
| July 3, 1986 | Letter from applicant concerning cable tray qualification program. |
| July 3, 1986 | Letter from applicant concerning FSAR revisions. |
| July 7, 1986 | Letter to applicant transmitting an environmental assessment for Appendix J exemption. |

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| July 8, 1986 | Letter from applicant concerning Generic Letter 83-28, additional information. |
| July 15, 1986 | Letter from applicant concerning control rod drop testing. |
| July 15, 1986 | Letter from applicant transmitting additional comments on Technical Specifications. |
| July 16, 1986 | Letter from applicant concerning completion of seismic qualification and pump and valve operability programs. |
| July 18, 1986 | Letter from applicant concerning natural circulation tests: SER Section 15.4.7.5 (License Condition No. 5) (Diablo Canyon test results). |
| July 22, 1986 | Letter from applicant concerning revised ODCM). |

# APPENDIX B

## BIBLIOGRAPHY

Berlinger, C., NRC, memorandum to V. Nerses, "RCP Trip, Seabrook Station Units 1 and 2," April 10, 1986.

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## APPENDIX D

## ACRONYMS AND INITIALISMS

| | |
|---|---|
| ANS | American Nuclear Society |
| ANSI | American National Standards Institute |
| ASDV | atmospheric steam dump valve |
| ASME | American Society of Mechanical Engineers |
| ASTM | American Society for Testing and Materials |
| ATWS | anticipated transient without scram |
| BIT | boron injection tank |
| BOL | beginning of life |
| BOP | balance of plant |
| BTP | branch technical position |
| CCW | component cooling water |
| CFR | *Code of Federal Regulations* |
| CILRT | containment integrated leak rate test |
| CRT | cathode ray tube |
| CS | containment spray |
| CSF | critical safety function |
| DCRDR | detailed control room design review |
| DG | diesel generator |
| DOE | U.S. Department of Energy |
| DNB | departure from nucleate boiling |
| DNBR | departure from nucleate boiling ratio |
| ECCS | emergency core cooling system |
| EFW | emergency feedwater |
| EFWS | emergency feedwater system |
| EOL | end of life |
| EOP | emergency operating procedure |
| EPIA | Emergency Plan Implementation Appraisal |
| ESF | engineered safety feature(s) |
| FM | Factory Mutual |
| FSAR | Final Safety Analysis Report |
| GA | General Atomics |
| GDC | general design criterion(a) |
| HELB | high-energy line break |
| HEPA | high efficiency particulate air |
| HPDS | Health Physics Department Supervisor |
| I&C | instrumentation and control |
| ICC | inadequate core cooling |

| | |
|---|---|
| ID | inside diameter |
| IE | Office of Inspection and Enforcement |
| IEEE | Institute of Electrical and Electronics Engineers |
| INEL | Idaho National Engineering Laboratory |
| IRTU | intelligent remote terminal unit |
| ISEG | Independent Safety Engineering Group |
| ISI | inservice inspection |
| IST | inservice test |
| LOCA | loss-of-coolant accident |
| LPMS | loose parts monitoring system |
| MCB | main control board |
| MCC | motor control center |
| MSIV | main steam isolation valve |
| msl | mean sea level |
| MSLB | main steamline break |
| NFPA | National Fire Protection Association |
| NHY | New Hampshire Yankee |
| NPS | nominal pipe size |
| NPSH | net positive suction head |
| NQG | Nuclear Quality Group |
| NRC | U.S. Nuclear Regulatory Commission |
| NSSS | nuclear steam supply system |
| OBE | operating basis earthquake |
| ODCM | Offsite Dose Calculation Manual |
| OL | operating license |
| OQAP | operational quality assurance program |
| PAB | primary auxiliary building |
| PASS | postaccident sampling system |
| PCCW | primary containment cooling water |
| PCP | process control program |
| P&ID | piping and instrumentation diagram |
| PMH | probable maximum hurricane |
| PORC | Plant Operations Review Committee |
| PORV | power-operated relief valve |
| PROM | programmable read only memory |
| PRT | pressurizer relief tank |
| PSI | preservice inspection |
| PSNH | Public Service Company of New Hampshire |
| PVORT | Pump and Valve Operability Review Team |
| QA | quality assurance |
| RCP | reactor coolant pump |
| RCS | reactor coolant system |
| RDMS | radiation data management system |
| RETS | Radiological Effluent Technical Specification |
| RG | regulatory guide |
| RHR | residual heat removal |
| RL | refracted longitudinal |
| RRS | required response spectrum(a) |

| | |
|---|---|
| RSS | remote safe shutdown |
| RSS | remote shutdown system |
| RTB | reactor trip breaker |
| RTD | resistance temperature detector |
| RTS | repetitive task sheet |
| RVLIS | reactor vessel level instrumentation system |
| RWST | refueling water storage tank |
| SEPP | Supplemental Examination Program Plan |
| SER | Safety Evaluation Report |
| SG | steam generator |
| SI | safety injection |
| SNPP | Salem Nuclear Power Plant |
| SORC | Station Operations Review Committee |
| SPDS | safety parameter display system |
| SQRT | Seismic Qualification Review Team |
| SRO | senior reactor operator |
| SRP | Standard Review Plan |
| SSE | safe shutdown earthquake |
| SSER | Supplement to Safety Evaluation Report |
| SSPS | solid state protection system |
| STA | shift technical advisor |
| SWPS | solid waste processing system |
| TA | tower actuation |
| TCCC | thermocouple conversion cabinet |
| TER | Technical Evaluation Report |
| TMI | Three Mile Island |
| TRS | test response spectrum(a) |
| TS | Technical Specification |
| UL | Underwriters Laboratories |
| UVTA | undervoltage trip attachment |
| VAS | video alarm system |
| V&V | verification and validation |
| WOG | Westinghouse Owners Group |
| YNSD | Yankee Nuclear Services Division |

## APPENDIX F

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# APPENDIX H

## ERRATA TO THE SEABROOK STATION SAFETY EVALUATION REPORT AND ITS SUPPLEMENTS

(Unless otherwise noted, all changes listed below apply to the SER.)

Section 2.4.1, page 2-21, 7th line from top of page
Add "peak" after "additional".

Section 2.4.3, page 2-22, 20th line from bottom of page
Change "Section 2.4.3.6" to "Section 2.4.5".

Section 2.5.1.2, page 2-33, 8th line from top of page
Delete "en".

Section 3.4.1, page 3-6, 14th line from top of page
Change "is 20.5" to "would be less than 21.0".

Section 3.4.1, page 3-6, 18th line from top of page
Delete "the 20.5 ft msl"; change "elevation" to "elevations"; and add "up to 21.0 ft msl" after "elevations".

Section 3.4.1, page 3-6, 19th and 20th lines from top of page
Change "opening" to "openings", "wall" to "walls", "is at" to "are below", and "fuel" to "new and spent fuel".

Section 3.4.1, page 3-6, 21st line from top of page
Add "and access to the residual heat removal and containment spray equipment vault (located at el 20.67 ft msl)" after "(located at el 20.5 ft msl)".

Section 3.4.1, page 3-6, 21st and 22nd lines from top of page
Change "Flood protection for this building is provided by a curb at el 20.5 ft msl behind this door." to "Flood protection for critical areas of these buildings is provided by a concrete barrier to 25.0 ft msl to protect new and spent fuel and a high point of 21.0 ft msl, respectively.".

Section 3.6.2, page 3-18, 2nd line from top of page
Add "per FSAR pg 3-6(B)-6a" after "end".

Section 3.8.1, page 3-22, 11th line from bottom of page
Add "and Article CC-6000 of ASME Code, Section III, Division 2" after "RG 1.18".

Section 3.8.5, page 3-26, 2nd line from bottom of page
Add "except for the foundation of the containment structure, which was designed in accordance with ASME Code, Section III, Division 2" after "ACI 318-71".

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Section 3.8.5, page 3-27, 6th line from top of page

Add "and ASME Code, Section III, Division 2, as applicable" after "Code".

Section 3.8.5, page 3-27, 8th line from top of page

Add ", ASME Code, Section III, Division 2," after "Code".

Section 3.8.5, page 3-27, 12th line from top of page

Add ", ASME Code, Section III, Division 2," after "Code".

Section 3.9.2.2, page 3-32, 19th line from bottom of page

Delete sentence "All nonseismic...supported.".

Section 3.9.2.2, page 3-32, 18th line from bottom of page

Replace "classified as seismic Category I" with "designed to preclude failure under seismic loads".

Section 3.9.3.2, page 3-36, 2nd paragraph of the section, 2nd and 3rd sentences

Replace second and third sentences with "The three safety valves are designed without a water seal. The two power-operated relief valves have a small water seal. The design of the discharge piping for these two valves includes the reaction forces resulting from the water seal.".

Section 3.9.3.2, page 3-36, 4th paragraph of the section, 2nd sentence

Replace second sentence with "The safety valves have short-radius elbows on the discharge side and are assembled so as to minimize reaction force moment arms at the valve branch/main header intersection point.".

Section 4.3.2, page 4-21, 22nd line from bottom of page

Change "2.50" to "2.32".

Section 4.3.2, page 4-22, 4th line from top of page

Change "band" to "bank".

Supplement No. 3, Section 4.4.5.2, page 4-1, 19th line from top of page

Change "and" to "or".

Section 4.6, page 4-37, 20th line from top of page

Change "tanks" to "tank" and "(BITs)" to "(BIT)".

Section 5.2.1.1, page 5-2, 5th line from top of page

Change "find" to "finds".

Section 5.2.2.1, page 5-3, 4th paragraph of the section, 2nd sentence

Change "four" to "three" and delete "low main feedwater flow,".

Section 5.2.5, page 5-11, 4th line from top of page

Delete "provided in each line".

Section 5.3.1.2, page 5-15, 17th line from bottom of page

Change "Appendix X" to "Appendix IX".

Section 5.3.1.2, page 5-16, 21st line from top of page

Add "not" after "will".

Supplement No. 4, Section 5.4.2.1, page 5-8, 9th line from bottom of page
Replace "among" with "along".

Section 5.4.7.1, page 5-23, 8th line from bottom of page
Change "CVCSs" to "CVCS".

Section 5.4.7.1, page 5-24, 16th line from bottom of page
Add "and temperature is below 350°F" after "1000 psig".

Section 6.4, page 6-30, 7th paragraph of the section, 2nd sentence
Delete the second sentence.

Section 6.5.1.1, page 6-30, 2nd paragraph of the section, 4th sentence
Delete the fourth sentence.

Section 6.8, page 6-38, 17th line from top of page
Change "including" to "except the".

Section 6.8, page 6-38, 22nd and 23rd lines from top of page
Change "Group C" to "Group D" and add "and a Quality Group C stop-check valve" after "valves".

Section 6.8, page 6-38, 16th line from bottom of page
Change "Group C" to "Group B".

Supplement No. 4, Section 7.3.2.6, page 7-10, 13th line from top of page
Replace "512 amps" with "5.12 amps".

Section 7.6.7.6, page 7-45, 3rd paragraph of the section, 4th sentence
Delete the fourth sentence.

Section 7.7.1.8, page 7-51, 13th line from top of page
Replace "turbine" with "plant".

Section 8.3.1.1.3, page 8-7, 15th line from top of page
Change "associated non-Class 1E bus" to "own terminals".

Section 8.3.1.7.8, page 8-10, 7th line from top of page
Change "8.3.1.7.8" to "8.3.1.2.8".

Section 8.3.1.7.8, page 8-10, 13th and 14th lines from top of page
Delete "," after "signal"; add "and" after "signal"; delete "and there are low ambient conditions".

Supplement No. 4, Section 8.3.1.8, page 8-10, 25th and 26th lines from top of page
Replace "is a dc power feed to the inverter from battery 1C which is designated as channel III" with "connects the output of the inverter to panel PP-1C which is designated as channel III".

Supplement No. 4, Section 8.3.1.8, page 8-10, 29th and 30th lines from top of page

Replace "is a dc power feed to the inverter from battery 1D designated as channel IV" with "connects the output of the inverter to distribution panel PP-1D which is designated as channel IV".

Supplement No. 4, Section 8.3.2.2, page 8-14, 17th line from bottom of page

Change "15 inches" to "±5 inches".

Section 8.3.3.3.1, page 8-18, 2nd and 3rd lines from bottom of page

Delete ", located outside the nuclear island, or in a nonseismic structure,".

Section 9.2.1, page 9-11, 14th line from top of page

Add "damage due to the" after "cause".

Section 9.2.6, page 9-17, 2nd paragraph from bottom of page, 1st sentence

Add "seismic Category I" between "The" and "level" and delete ", but they are not themselves seismic Category I".

Section 9.3.2.1, page 9-20, 1st line at top of page

Change "closed" to "open" and "Category 1" to "Category I".

Section 9.4.1, page 9-24, 8th line from bottom of page

Delete "computer room,".

Section 9.4.1, page 9-24, 3rd paragraph of the section

Add "A separate system conditions the computer room." as a second sentence.

Section 9.4.1, page 9-25, 4th paragraph of the section, 2nd sentence

Replace "All ducting is seismically supported." with "All ducting is safety Class 3 and is seismically supported.".

Section 9.4.1, page 9-25, 7th line from top of page

Replace "a single" with "two 50%"; change "unit" to "units".

Section 9.4.1, page 9-25, 20th line from top of page

Replace "to the diesel generator building mechanical room and" with "directly outside the building and also by".

Section 9.4.1, page 9-26, 11th line from top of page

Change "outsie" to "outside".

Section 9.4.4, page 9-30, 21st line from top of page

Delete "do not".

Section 9.5.1.4, page 9-41, 9th line from top of page

Replace "adjacent to" with "near".

Section 9.5.1.4, page 9-42, 3rd line from top of page

Change "unit, feed" to "unit, hydraulic fluid power unit, feed".

Section 9.5.1.4, page 9-42, 13th line from top of page

Change "high-pressure gas" to "high-pressure bulk gas".

Section 9.5.1.4, page 9-42, 29th line from top of page
Add "and" after "containment".

Section 9.5.1.5, page 9-46, 10th line from top of page
Change "PAB-F-1K-2" to "PAB-F-1K-Z".

Section 9.5.1.5, page 9-46, 19th and 20th lines from top of page
Delete "and automatic connection to a Class 1E emergency power bus".

Section 9.5.1.5, page 9-46, last line at bottom of page
Change "fire is" to "fire pump is".

Section 9.5.1.5, page 9-47, 3rd and 4th lines from top of page
Delete ",or they are manually started by the operator in the control room".

Section 9.5.1.5, page 9-47, 16th line from top of page
Change "250 ft" to "approximately 250 ft".

Section 9.5.1.5, page 9-48, 1st line at top of page
Change "safe shutdown" to "safety-related".

Section 9.5.1.5, page 9-48, 10th and 11th lines from top of page
Change "in the computer room and quality assurance storage and document" to "secondary alarm station computer room in the turbine building and the document".

Section 9.5.1.6, page 9-49, 20th line from top of page
Change "cool" to "maintain habitability of".

Section 9.5.1.6, page 9-50, 10th line from top of page
Change "CC-V176" to "CC-V176 and CC-V256".

Section 9.5.1.6, page 9-51, 5th line from bottom of page
Delete "1/2-".

Section 9.5.1.6, page 9-52, 15th line from top of page
Change "an alternate shutdown system" to "alternate shutdown capability".

Section 9.5.1.6, page 9-52, 16th line from top of page
Change "system" to "capability".

Section 9.5.1.6, page 9-52, 6th line from bottom of page
Change "system" (last word on line) to "capability".

Section 9.5.1.6, page 9-52, 5th line from bottom of page
Change "system" to "capability".

Section 9.5.1.6, page 9-52, 3rd line from bottom of page
Change "A manual smoke ventilation system" to "Manual smoke ventilation".

Section 9.5.1.6, page 9-52, 2nd line from bottom of page
Delete "also".

Section 9.5.1.6, page 9-53, 1st line at top of page
Delete "sprinkler".

Section 9.5.1.6, page 9-53, 1st line at top of page
Change "heat" to "cross-zoned smoke".

Section 9.5.1.6, page 9-53, 23rd line from top of page
Change "Ionization smoke" to "Smoke".

Section 9.5.1.6, page 9-53, 25th line from top of page
Change "in the areas for fire manual" to "for manual fire".

Section 9.5.1.6, page 9-53, 7th line from bottom of page
Change "detection" to "suppression".

Section 9.5.1.6, page 9-54, 1st line at top of page
Delete "sprinkler".

Section 9.5.1.6, page 9-54, 6th line from bottom of page
Change "over" to "inside".

Section 9.5.1.6, page 9-54, last line at bottom of page
Change "area DG-F-3AB-A" to "areas DG-F-3A-Z and DG-F-3B-Z".

Section 9.5.1.6, page 9-54, last line at bottom of page
Change "50" to "51".

Section 9.5.1.6, page 9-55, 27th and 28th lines from top of page
Delete "Exterior building walls identified as 1-1/2-hour-minimum fire rating are concrete walls located below grade."

Section 9.5.1.6, page 9-55, 29th line from top of page
Change "deluge" to "preaction".

Section 9.5.1.6, page 9-55, 30th line from top of page
Change "heat" to "smoke and flame".

Section 9.5.1.6, page 9-57, 17th line from top of page
Change "B" to "A".

Section 9.5.1.6, page 9-57, 24th line from top of page
Change "1BA" to "1B-A".

Section 9.5.1.6, page 9-57, 4th line from bottom of page
Change "V5" to "V4".

Section 9.5.1.6, page 9-58, 23rd line from top of page
Change "EFT" to "EFP".

Section 9.5.1.6, page 9-59, 1st line at top of page
Change "SW-F-1E-A" to "SW-F-1E-Z".

Section 9.5.1.6, page 9-59, 18th line from top of page
Delete "only" and "the Unit 1".

Section 9.5.1.6, page 9-59, 19th line from top of page
Change "intakes" to "intake and discharge".

Section 9.5.1.6, page 9-59, 11th line from bottom of page
Change "Safety-Related" to "Shutdown".

Section 9.5.1.6, page 9-59, 8th line from bottom of page
Change "located at various points" to "installed".

Section 9.5.1.6, page 9-59, 2nd line from bottom of page
Change "safety" to "safe".

Section 9.5.1.6, page 9-61, 1st line at top of page
Change "safety-related" to "safe shutdown".

Section 9.5.2.1, page 9-63, 4th line from top of page
Replace "four" with "six" and "three" with "five".

Section 9.5.2.2, page 9-65, 21st line from top of page
Replace "48-v" with "48-V".

Section 9.5.3.1, page 9-66, 23rd line from top of page
Replace "a" with "A".

Section 9.5.4.1, page 9-68, 9th line from top of page
Change "9.5.5" to "9.5.6".

Section 9.5.4.1, page 9-70, 8th line from bottom of page
Replace "are" with "were".

Section 9.5.4.1, page 9-73, 15th line from top of page
Add "in lieu of relocating the fuel oil transfer pumps" after "heads".

Section 9.5.4.1, page 9-74, 3rd line from top of page
Replace "-10%°F" with "-10°F".

Section 9.5.4.2, page 9-76, 23rd line from bottom of page
Replace "Class 5" with "Class 3".

Section 9.5.7, page 9-84, 12th line from top of page
Delete ", except as noted,".

Section 9.5.8, page 9-85, 13th line from top of page
Replace "has" with "had".

Section 10.1, page 10-1, 17th line from top of page
Delete ", causing control rod movement".

Section 10.2, page 10-1, 24th line from top of page
Add "and" after "limits,".

Section 10.4.1, page 10-7, 17th line from top of page
Add "or" between "reactor" and "to".

Section 10.4.2.1, page 10-8, 10th line from top of page
Add "manually" after "be".

Section 10.4.3.2, page 10-9, 2nd paragraph of the section, 2nd sentence
Delete the second sentence.

Section 10.4.4, page 10-9, 23rd line from top of page
Replace "generator" with "generation".

Section 10.4.7, page 10-11, 18th line from top of page
Add "and portions of the feedwater system used for emergency feedwater" after "integrity".

Section 10.4.7, page 10-11, 21st line from bottom of page
Replace "auxiliary" with "emergency".

Section 10.4.7, page 10-11, 2nd line from bottom of page
Replace "auxiliary" with "emergency".

Section 10.4.7, page 10-12, 3rd line from top of page
Replace "auxiliary" with "emergency".

Section 11.5.1, page 11-13, Table 11.6, 3rd column of table
Under the word "Monitoring" add "(or sampling)".

Section 11.5.1, page 11-14, Table 11.16 (continued), 3rd column of table
Under the word "Monitoring" add "(or sampling)."

Section 12.3.4.2, page 12-7, 23rd line from top of page
Change "upstream" to "downstream".

Section 14, page 14-3, 18th line from top of page
Replace "were adequate to handle all ESF loads" with "will be demonstrated to handle all ESF loads to the extent practical during hot functional testing".

Section 15.4.2, page 15-11, 21st line from bottom of page
Replace "in" with "is".

Section 17.2, page 17-1, 14th line from bottom of page
Add "Department" after "Assurance".

Section 17.2, page 17-4, 12th line from top of page
Add "Nuclear" before "Production".

Section 17.3, page 17-5, 16th line from top of page
Replace "and to determine" with "investigate to determine".

# APPENDIX K

## EXEMPTION FROM A PORTION OF GENERAL DESIGN CRITERION 4 OF APPENDIX A TO 10 CFR 50

## UNITED STATES NUCLEAR REGULATORY COMMISSION

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | |
| PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE, ET AL.* | ) | Docket Nos. 50-443 and 50-444 |
| (Seabrook Station, Units 1 and 2) | ) | |
| | ) | |

## EXEMPTION

### I.

On March 30, 1973, Public Service Company of New Hampshire, et al. (applicants) tendered an application for licenses to construct Seabrook Station, Units 1 and 2 (Seabrook or the facility) with the Atomic Energy Commission (currently the Nuclear Regulatory Commission or the Commission). Following a public hearing before the Atomic Safety and Licensing Board, the Commission issued Construction Permit Nos. CPPR-135 and CPPR-136 permitting the construction of the Units 1 and 2, respectively, on July 7, 1976. Each unit of the facility is a pressurized water reactor, containing a Westinghouse Electric Company nuclear steam supply system, located at the applicants' site in Seabrook, New Hampshire.

On June 29, 1981, the applicants tendered an application for Operating Licenses for the facilities, currently in the licensing review process.

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*The current construction permit holders for Seabrook Station are: Bangor Hydor-Electric Company, Canal Electric Company, Central Maine Power Company, Central Vermont Public Service Corporation, Connecticut Light & Power Company, Fitchburg Gas & Electric Light Company, Hudson Light & Power Department, Maine Public Service Company, Massachusetts Municipal Wholesale Electric Company, Montaup Electric Company, New England Power Company, New Hampshire Electric Cooperative, Inc., Public Service Company of New Hampshire, Taunton Municipal Lighting Plant, United Illuminating Company, Vermont Electric Generation and Transmission Cooperative, Inc., and Washington Electric Cooperative, Inc.

## II.

The Construction Permits issued for constructing Units 1 and 2 of the Seabrook Station provide, in pertinent part, that the facility is subject to all rules, regulations and orders of the Commission. This includes General Design Criterion (GDC) 4 of Appendix A to 10 CFR 50. GDC 4 requires that structures, systems and components important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with the normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents. These structures, systems and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, discharging fluids that may result from equipment failures, and from events and conditions outside the nuclear power unit.

In a submittal dated August 9, 1984, the applicants enclosed Westinghouse Report WCAP-10567 (Reference 1) containing the technical basis for their request to eliminate the postulated breaks in the reactor coolant loop (RCL) piping of Seabrook Station, Units 1 and 2. The applicants further stated that eliminating these postulated breaks would result in eliminating their associated dynamic effects which are specifically defined as the effects of missiles, pipe whipping, and fluid jets. In the February 1, 1985 submittal, the applicants stated that granting of their request (1) eliminates the need to postulate longitudinal and circumferential pipe breaks in the RCL primary piping (hot leg, cold leg, and crossover leg piping); (2) eliminates the need to install associated pipe whip restraints in the RCL primary piping; and (3) eliminates the requirement to analyze and design for the dynamic effects of these breaks including jet impingement, reactor cavity pressurization and load combination assumptions. The exemption request will not apply to the containment design bases, the emergency core cooling system, or environmental qualification, engineered safety features systems response, or the design of the RCS heavy component supports.

The applicants' submittal of February 1, 1985, contains the results of an analysis of the occupational radiation dose reduction which provides the value-impact analysis for Seabrook Station, Units 1 and 2. The technical information contained in Reference (1) together with the value-impact analysis, provided a comprehensive justification for requesting limited exemptions from the requirements of GDC 4.

From the deterministic fracture mechanics analysis contained in the technical information furnished, the applicants concluded that postulated breaks up to and including the double-ended guillotine breaks (DEGB) of the primary loop coolant piping in Seabrook 1 and 2 need not be considered as a design basis for installing protective structures, such as pipe whip restraints and jet impingement shields, to guard against the dynamic effects associated with such postulated breaks. However, the applicants will continue to postulate the equivalent area of a DEGB as the design basis for the containment, the ECCS, the engineered safety systems response, environmental qualification and the design of the RCS heavy component supports.

## III.

The Commission's regulations require that applicants provide

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protective measures against the dynamic effects of postulated pipe breaks in high energy fluid system piping. Protective measures include physical isolation from postulated pipe rupture locations, if feasible, or the installation of pipe whip restraints, jet impingement shields or compartments. In 1975, concerns arose as to the asymmetric loads on pressurized water reactor (PWR) vessels and their internals which could result from these large postulated breaks at discrete locations in the main primary coolant loop piping. This led to the establishment of Unresolved Safety Issue (USI) A-2, "Asymmetric Blowdown Loads on PWR Primary Systems."

The NRC staff, after several review meetings with the Advisory Committee on Reactor Safeguards (ACRS) and a meeting with the NRC Committee to Review Generic Requirements (CRGR), concluded that an exemption from the regulations would be acceptable as an alternative for resolution of USI A-2 for sixteen facilities owned by eleven licensees in the Westinghouse Owners' Group (one of these facilities, Fort Calhoun, has a Combustion Engineering nuclear steam supply system). This NRC staff position was stated in Generic Letter 84-04, published on February 1, 1984 (Reference 2). The generic letter states that the affected licensees must justify an exemption to GDC 4 on a plant-specific basis. Other PWR applicants or licensees may request similar exemptions from the requirements of GDC 4 provided that they submit an acceptable technical basis for eliminating the need to postulate pipe breaks.

The acceptance of an exemption was made possible by the development of advanced fracture mechanics technology. These advanced fracture mechanics techniques deal with relatively small flaws in piping components (either postulated or real) and examine their behavior under various pipe loads. The objective is to demonstrate by deterministic analyses that the detection of small flaws by either inservice inspection or leakage monitoring systems is assured long before the flaws can grow to critical or unstable sizes which could lead to large break areas such as the DEGB or its equivalent. The concept underlying such analyses is referred to as "leak-before-break" (LBB). There is no implication that piping failures cannot occur, but rather that improved knowledge of the failure modes of piping systems and the application of appropriate remedial measures, if indicated, can reduce the probability of catastrophic failure to insignificant values.

Advanced fracture mechanics technology was applied in topical reports (References 3, 4, and 5) submitted to the staff by Westinghouse on behalf of the licensees belonging to the USI A-2 Owners' Group. Although the topical reports were intended to resolve the issue of asymmetric blowdown loads that resulted from a limited number of discrete break locations, the technology advanced in these topical reports demonstrated that the probability of breaks occurring in the primary coolant system main loop piping is sufficiently low such that these breaks need not be considered as a design basis for requiring installation of pipe whip restraints or jet impingement shields. The staff's Topical Report Evaluation is included as a part of Reference 2.

Probabilistic fracture mechanics studies conducted by the Lawrence Livermore National Laboratories (LLNL) on both Westinghouse and Combustion Engineering nuclear steam supply system main loop piping (Reference 6) confirm that both the probability of leakage (e.g., undetected flaw growth through the pipe wall by fatigue) and the probability of a DEGB are very low. The results given in Reference 6 are that the best-estimate leak probabilities for Westinghouse nuclear steam supply system main loop piping range from $1.2 \times 10^{-8}$ to $1.5 \times 10^{-7}$ per plant year and the best-estimate DEGB probabilities range from $1 \times 10^{-12}$ to $7 \times 10^{-12}$ per plant year. Similarly, the best-estimate leak probabilities for Combustion Engineering nuclear steam supply system main loop piping range from $1 \times 10^{-8}$ per plant year to $3 \times 10^{-8}$ per plant year, and the best-estimate DEGB probabilities range from $5 \times 10^{-14}$ to $5 \times 10^{-13}$ per plant year. The results do not affect core melt probabilities in any significant way.

During the past few years it has also become apparent that the requirement for installation of large, massive pipe whip restraints and jet impingement shields is not necessarily the most cost effective way to achieve the desired level of safety, as indicated in Enclosure 2, Regulatory Analysis, to Reference 2. Even for new plants, these devices tend to restrict access for future inservice inspection of piping; or if they are removed and reinstalled for inspection, there is a potential risk of damaging the piping and other safety-related components in this process. If installed in operating plants, high occupational radiation exposure (ORE) would be incurred while public risk reduction would be very low. Removal and reinstallation for inservice inspection also entail significant ORE over the life of a plant.

## IV.

The primary coolant system of Seabrook, Units 1 and 2 described in Reference 1, has four main loops each comprising a 33.9 inch diameter (outside) hot leg, a 37.5 inch diameter crossover leg and 32.4 inch diameter cold leg piping. The materials in the primary loop piping are wrought stainless steel pipe with cast stainless steel fittings and associated welds. In its review of Reference 1, the staff evaluated the Westinghouse analyses with regard to:

- the location of maximum stresses in the piping, associated with combined loads from normal operation and the SSE;
- potential cracking mechanisms;
- size of through-wall cracks that would leak a detectable amount under normal loads and pressure;
- stability of a "leakage-size crack" under normal plus SSE loads and the expected margin in terms of load;
- margin based on crack size; and
- the fracture toughness properties of wrought and thermally-aged cast stainless steel piping and weld material.

The NRC staff's criteria for evaluation of the above parameters are delineated in its Topical Report Evaluation, Enclosure 1 to Reference 2, Section 4.1, "NRC Evaluation Criteria", and are as follows:

(1) The loading conditions should include static forces and moments (pressure, deadweight and thermal expansion) due to normal operation, and the forces and moments associated with the safe shutdown earthquake (SSE). These forces and moments should be located where the highest stresses and the lowest material toughness are coincident for base materials, weldments and safe-ends.

(2) For the piping run/systems under evaluation, all pertinent information which demonstrates that degradation or failure of the piping resulting from stress corrosion cracking, fatigue or water hammer is not likely, should be provided. Relevant operating history should be cited, which includes system operational procedures; system or component modification; water chemistry parameters, limits and controls; resistance of material to various forms of stress corrosion, and performance under cyclic loadings.

(3) A through-wall crack should be postulated at the highest stressed locations determined from (1) above. The size of the crack should be large enough so that the leakage is assured of detection with adequate margin using the minimum installed leak detection capability when the pipe is subjected to normal operational loads.

(4) It should be demonstrated that the postulated leakage crack is stable under normal plus SSE loads for long periods of time;

that is, crack growth, if any, is minimal during an earthquake. The margin, in terms of applied loads, should be determined by a crack stability analysis, i.e., that the leakage-size crack will not experience unstable crack growth even if larger loads (larger than design loads) are applied. This analysis should demonstrate that crack growth is stable and the final crack size is limited, such that a double-ended pipe break will not occur.

(5) The crack size margin should be determined by comparing the leakage-size crack to critical-size cracks. Under normal plus SSE loads, it should be demonstrated that there is adequate margin between the leakage-size crack and the critical-size crack to account for the uncertainties inherent in the analyses, and leakage detection capability. A limit-load analysis may suffice for the purpose; however, an elastic-plastic fracture mechanics (tearing instability) analysis is preferable.

(6) The materials data provided should include types of materials and materials specifications used for base metal, weldments and safe-ends, the materials properties including the J-R curve used in the analyses, and long-term effects such as thermal aging and other limitations to valid data (e.g. J maximum, maximum crack growth).

## V.

Based on its evaluation of the analysis contained in Westinghouse Report WCAP-10567 (Reference 1), the staff finds that the applicants have presented an acceptable technical justification, addressing the above criteria, for not installing protective devices to deal with the dynamic effects of large pipe ruptures in the main loop primary coolant system piping of Seabrook Station, Units 1 and 2. This finding is predicated on the fact that each of the parameters evaluated for Seabrook is enveloped by the generic analysis performed by Westinghouse in Reference 3, and accepted by the staff in Enclosure 1 to Reference 2. Specifically:

(1) The loads associated with the highest stressed location in the main loop primary system piping are 2332 kips (axial), 37,045 in-kips (bending moment) and result in maximum stresses of about 97% of the bounding stress used by Westinghouse in Reference 3. Further, these loads are approximately 88% of those established by the staff as limits .

(2) For Westinghouse plants, there is no history of cracking failure in reactor primary coolant system loop piping. The Westinghouse reactor coolant system primary loop has an operating history which demonstrates its inherent stability. This includes a low susceptibility to cracking failure from the effects of corrosion (e.g. intergranular stress corrosion cracking), water

hammer, or fatigue (low and high cycle). This operating history totals over 400 reactor-years, including five (5) plants each having 15 years of operation and 15 other plants with over 10 years of operation.

(3) The leak rate calculations performed for the Seabrook plants using an initial through-wall crack of 7.5 inches are identical to those of Enclosure 1 to Reference 2. The Seabrook plants have an RCS pressure boundary leak detection system which is consistent with the guidelines of Regulatory Guide 1.45, and it can detect leakage of one (1) gpm in one hour. The calculated leak rate through the postulated flaw results in a factor of at least 10 relative to the sensitivity of the Seabrook plants' leak detection system.

(4) The margin in terms of load based on fracture mechanics analyses for the leakage-size crack under normal plus SSE loads is within the bounds calculated by the staff in Section 4.2.3 of Enclosure 1 to Reference 2. Based on a limit-load analysis, the load margin is about 2.0 and based on the J-limit, the margin is at least 1.1.

(5) The margin between the leakage-size crack and the critical-size crack was calculated by a limit-load analysis. Again, the results demonstrated that a margin of at least 3 on crack size exists and is within the bounds of Section 4.2.3 of Enclosure 1 to Reference 2.

(6) In addition to the wrought stainless steel pipes, the Seabrook units have cast stainless steel fittings and associated welds in the primary coolant system. As an integral part of its review, the staff's evaluation of the properties data of Reference 7 is enclosed as Appendix I to this exemption. In Reference 7, data for ten (10) plants are presented and lower bound or "worst case" materials properties were identified and used in the analysis performed in the Reference 1 report by Westinghouse. The applied J for Seabrook in Reference 1 for cast stainless steel fittings was less than 3000 in-lb/in$^2$. Hence, the staff's upper bound 3000 in-lb/in$^2$ on the applied J (refer to Appendix I, page 6) was not exceeded.

In view of the analytical results presented in the Westinghouse Report for Seabrook (Reference 1) and the staff's evaluation findings related above, the staff concludes that the probability of large pipe breaks occurring in the primary coolant system loops of Seabrook Station, Units 1 and 2, is sufficiently low such that pipe breaks and their associated dynamic loading effects as indicated in the applicants submittals need not be considered as a design basis for requiring pipe whip restraints and jet impingement shields. These dynamic loading effects include pipe whip, jet impingement, missiles, reactor cavity overpressurization, and load combination assumptions. Eliminating the need to consider these dynamic loading effects for this particular application will not in any way affect the design bases for the containment, the emergency core cooling system, the design of RCS heavy component supports, the engineered safety features systems response, or the environmental qualification of equipment for Seabrook.

However, in order to provide the Commission with an opportunity to consider the long term aspects of the NRC staff's recent acceptance of the "leak-before-break" approach, these limited exemptions are restricted to a period extending until the completion of the second refueling outage of Seabrook Station, Unit 1, pending the outcome of Commission rulemaking on this issue.

The staff also reviewed the value-impact analysis provided by the applicants in their submittal for not providing protective structures against postulated reactor coolant system loop pipe breaks to assure as low as reasonably achievable (ALARA) exposure to plant personnel. Consideration was given to design features for reducing doses to personnel who must operate, service and maintain the Seabrook instrumentation, controls, equipment, etc. The Seabrook value-impact analysis shows that the elimination of protective devices for RCS pipe breaks will save an occupational dose for plant personnel of approximately 1400 person-rem for both units over their operating lifetime. The staff review of the analysis shows it to be a reasonable estimate of dose savings. Therefore, with respect to occupational exposure and ALARA considerations, the staff finds that there is a radiological benefit to be gained by eliminating the need for the protective structures.

## VI.

In view of the staff's evaluation findings, conclusions, and recommendations above, the Commission has determined that, pursuant to 10 CFR 50.12(a), the following exemption is authorized by law and will not endanger life or property or the common defense and security, and are otherwise in the public interest. The Commission hereby approves the requested schedular limited exemption from GDC 4 of Appendix A to 10 CFR Part 50, to permit the applicants to eliminate the protective devices and the dynamic loading effects, as described in Part II of this exemption, associated with the postulated primary loop pipe breaks for Seabrook Station, Units 1 and 2. The exemption will expire upon completion of the GDC 4 rulemaking changes but no later than the second refueling outage of Seabrook Station, Unit 1.

Pursuant to 10 CFR 51.32, the Commission has determined that the issuance of the exemption will have no significant impact on the environment (50 FR 47468).

The exemption will become effective upon date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Hugh L. Thompson

Hugh L. Thompson, Jr., Director
Division of Licensing
Office of Nuclear Reactor Regulation

Dated at Bethesda, Maryland
this 22day of November, 1985

## REFERENCES

(1) Westinghouse report WCAP-10567, "Technical Bases for Eliminating Large Primary Loop Pipe Ruptures as the Structural Design Basis for Seabrook, Units 1 and 2, June 1984, Westinghouse Class 2 proprietary.

(2) NRC Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Breaks in PWR Primary Main Loops," February 1, 1984.

(3) Mechanistic Fracture Evaluation of Reactor Coolant Pipe Containing a Postulated Circumferential Throughwall Crack, WCAP-9558, Rev. 2, May 1981, Westinghouse Class 2 proprietary.

(4) Tensile and Toughness Properties of Primary Piping Weld Metal for Use in Mechanistic Fracture Evaluation, WCAP-9787, May 1981, Westinghouse Class 2 proprietary.

(5) Westinghouse Response to Questions and Comments Raised by Members of ACRS Subcommittee on Metal Components During the Westinghouse Presentation of September 25, 1981, Letter Report NS-EPR-2519, E.P. Rahe to Darrell G. Eisenhut, November 10, 1981, Westinghouse Class 2 proprietary.

(6) Lawrence Livermore National Laboratory Report, UCRL-86249, "Failure Probability of PWR Reactor Coolant Loop Piping," by T. Lo, H. H. Woo, G. S. Holman and C. K. Chou, February 1984 (Reprint of a paper intended for publication).

(7) Westinghouse Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," November 1983, Westinghouse Class 2 proprietary.

NOTE: Non-proprietary versions of References 1, 3, 4, 5 and 7 are available in the NRC Public Document Room as follows:

(1) WCAP 10566
(3) WCAP 9570
(4) WCAP 9788
(5) Non-proprietary version attached to the Letter Report
(7) WCAP 10457

# APPENDIX I

## Evaluation of Westinghouse Report WCAP 10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems"

### INTRODUCTION

The primary coolant piping in some Westinghouse Nuclear Steam Supply Systems (NSSS) contain cast stainless steel base metal and weld metal. The base metal and weld metal are fabricated to produce a duplex structure of delta (w) ferrite in an austenitic matrix. The duplex structure produces a material that has a higher yield strength, improved weldability and greater resistance to intergranular stress corrosion cracking than a single phase austenitic material. However, as early as 1965 (Ref.1), it was recognized that long time thermal aging at primary loop water temperatures (550°F-650°F) could significantly affect the Charpy impact toughness of the duplex structured alloys. Since the Charpy impact test is a measure of a material's resistance to fracture, a loss in Charpy impact toughness could result in reduced structural stability in the piping system.

The purpose of Report WCAP 10456 is to evaluate whether cast stainless steel base metal and weld metal containing postulated cracks will be sensitive to unstable fracture during the 40 year life of a nuclear power plant. In order to determine whether a piping system will behave

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in such a fashion, the pipe materials' mechanical properties, design criteria and method of predicting failure must be established. In this evaluation, we will assess the mechanical properties of thermally aged cast stainless steel pipe materials, which are reported in Report WCAP 10456.

## DISCUSSION

### 1. Weld Metal

Report WCAP 10456 refers to test results reported in a paper by Slama, et.al. (Ref. 2) to conclude that the weld metal in primary loop piping would not be overly sensitive to aging and that the aged cast pipe base metal material would be structurally limiting. In the Slama report eight (8) welds were evaluated. The tensile properties were only slightly affected by aging. The Charpy U-notch impact energy in the most highly sensitive weld decreased from 7daJ/cm$^2$ (40 ft-lbs) to near 4daJ/cm$^2$ (24 ft-lbs) after aging for 10,000 hours at 400°C (752°F). This change was not considered significant. The relatively small effect of aging on the weld, as compared to cast pipe material was reported to be caused by a difference in microstructure and lower levels of ferrite in the weld than in the cast pipe material.

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## 2. Cast Stainless Steel Pipe Base Metal

Report WCAP 10456 contains mechanical property test results from a number of heats of aged cast stainless steel material and a metallurgical study, which was performed by Westinghouse, to support a statistically based model for predicting the effect of thermal aging on the Charpy impact test properties of cast stainless steel. As a result of these tests and the proposed model, Westinghouse concludes that the fracture toughness test results from one heat of material tested represents end-of-life conditions for the ten (10) plants surveyed. The ten (10) plants surveyed are identified as Plants A through J.

### a. Mechanical Property Test Results Reported in WCAP 10456

Mechanical property test results on aged and unaged cast stainless steel materials which were reported in a paper by Landerman and Bamford (Ref. 3), Bamford, Landerman and Diaz (Ref. 4), Slama et. al. (Ref. 2) were discussed in Report 10456. In addition, Westinghouse performed confirmatory Charpy V notch and J-integral tests on aged cast stainless steel material, which was tested and evaluated by Slama et. al.

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The results of these tests indicate that:

(1) The fatigue crack growth rate of aged or unaged material in air and pressurized water reactor environments were equivalent.

(2) Tensile properties were essentially unaffected except for a slight increase in tensile strength and a decrease in ductility.

(3) J-integral test results indicate that the $J_{1C}$ and tearing modulus, T, are affected by aging.

b. Mechanism Study in WCAP 10456

The tests and literature survey conducted by Westinghouse indicate that the proposed mechanism of aging occurs in the range of operating temperatures for pressurized water reactors and the data from accelerated aging studies can be used to predict the behavior at operating temperatures.

## c. Cast Stainless Steel Pipe Test

The materials data discussed in the previous section of this evaluation were obtained from small specimens. As a consequence, the J-R results are limited to relatively short crack extensions. To investigate the behavior of cast stainless steel in actual piping geometry, Westinghouse performed two experiments, one of which was with thermally aged cast stainless steel and the other test was identical except that the steel was not thermally aged.

Each pipe tested contained a throughwall circumferential crack to the extent specified in WCAP 10456. The pipe sections were closed at the ends, pressurized to nominal PWR operating pressure and then bending loads were applied.

The results of the tests were very similar, in that both pipes displayed extensive ductility, and stable crack extension. There was no observed unstable crack extension or fast fracture.

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The results of the Westinghouse pipe experiments indicate that cast stainless steel, both aged and unaged, can withstand crack extensions well beyond the range of the J-R results with small specimens. However, if crack extension is predicted in an actual application of thermally aged cast stainless steel in a piping system, we believe that it is prudent to limit the applied J to 3000 in-lbs/$in^2$ or less unless further studies and/or experiments demonstrate that higher values are tolerable. Loss of initial toughness due to thermal aging of cast stainless steels at normal nuclear facility operating temperatures occurs slowly over the course of many years; therefore, continuing study of the aging phenomenon may lead to a relaxation of this position. Conversely, in the unlikely event that the total loss of toughness and the rate of toughness loss are greater than those projected in this evaluation, the staff will take appropriate action to limit the values to that which can be justified by experimental data. Because the aging is a slow process, the staff believes there would be sufficient time for the staff to recognize the problem and to rectify the situation. However, the staff believes this situation is highly unlikely because the staff has accepted only the lower bounds of data that were gathered among ten plants encompassing the range of materials in use.

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d. Effects of Thermal Aging on Westinghouse Supplied Centrifugally Cast Reactor Coolant Piping Reported in WCAP 10456

The reactor coolant cast stainless steel piping materials in the plants identified in WCAP 10456 as A through J, were produced to the specification SA-351, Class CF8A as outlined in ASME Code Section II, Part A and also to Westinghouse Equipment Specification G-678864, as revised. For these materials, Westinghouse has calculated the predicted end-of-life Charpy U-notch properties, based on their proposed model. The two (2) standard deviation end-of-life lower limit value for all the plants surveyed was greater than the Charpy V notch properties of the aged reference materials, which Westinghouse indicates represents end-of-life properties for all the plants. As a result, Westinghouse concluded that the amount of embrittlement in the aged reference material exceed the amount projected at end-of-life for all cast stainless steel pipe materials in Plants A through J.

## Conclusions

Based on our review of the information and data contained in Westinghouse Report WCAP 10456, we conclude that:

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1. Weld metal that is used in cast stainless steel piping system is initially less fracture resistant than the cast stainless steel base metal. However, the weld metal is less susceptible to thermal aging than the cast stainless steel base metal. Hence, at end-of-life the cast stainless steel base metal is anticipated to be the least fracture resistant material.

2. The Westinghouse proposed model may be used to predict the relative amount of embrittlement on a heat of cast stainless steel material. The two standard deviation lower confidence limit for this model will provide a useful engineering estimate of the predicted end-of-life Charpy impact properties for cast stainless steel base metal.

3. Since there is considerable scatter in J-integral test data for the heats of material tested, lower bound values for $J_{1c}$ and T should be used as engineering estimates for the fracture resistance of the aged reference material. We believe these values should also provide a lower bound for the fracture resistance of aged and unaged weld metal. If crack extension is predicted in an actual application of cast stainless steel in a piping system, we conclude that the applied J should be limited to 3000 in-lbs/in$^2$ or less unless further studies and tests demonstrate that higher values are tolerable. The Westinghouse pipe tests demonstrate that this may be possible.

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4. Since the predicted end-of-life Charpy impact values for the materials in Plants A through J are greater than the value measured for the aged reference material, the lower bound fracture properties for aged reference material may be used to determine the fracture resistance for the cast stainless steel material in Plants A through J.

# REFERENCES

(1) F. H. Beck, E. A. Schoefer, J. W. Flowers, M. E. Fontana, "New Cast High Strength Alloy Grades by Structural Control," ASTM STP 369 (1965)

(2) G. Slama, P. Petrequin, S. H. Masson, T. R. Mager, "Effect of Aging on Mechanical Properties of Austenitic Stainless Steel Casting and Welds," presented at SMIRT 7 Post Conference Seminar 6 - Assuring Structural Integrity of Steel Reactor Pressure Boundary Components, August 29/30, 1983, Monterey, Ca.

(3) E. I. Landerman and W. H. Bamford, "Fracture Toughness and Fatigue Characteristics of Centrifugally Cast Type 316 Stainless Steel After Simulated Thermal Service Conditions Presented at the Winter Annual Meeting of the ASME, San Francisco, Ca., December 1978 (MPC-8 ASME)

(4) W. H. Bamford, E. I. Landerman and E. Diaz, "Thermal Aging of Cast Stainless Steel and Its Impact on Piping Integrity." Presented at ASME Pressure Vessel and Piping Conference, Portland, Oregon, June 1983. To be published in ASME Trans.

7590-01

# UNITED STATES NUCLEAR REGULATORY COMMISSION

# PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE, ET. AL.*

# SEABROOK STATION, UNITS 1 AND 2

# DOCKET NOS. 50-443 AND 50-444

# ENVIRONMENTAL ASSESSMENT AND FINDING OF NO SIGNIFICANT IMPACT

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of an Exemption from a portion of the requirements of General Design Criterion (GDC) 4 (10 CFR 50, Appendix A) to the Public Service Company of New Hampshire, et. al. (the applicants), for the Seabrook Station, Units 1 and 2, located at the applicants' site in Seabrook, New Hsmpshire.

## ENVIRONMENTAL ASSESSMENT:

Identification of Proposed Action: The Exemption would permit eliminating the need to install the pipe whip restraints and jet impingement shields and their dynamic effects associated with postulated pipe breaks in eight locations per loop in the Seabrook Units 1 and 2 primary coolant systems, on the basis of advanced calculational methods for assuring that piping stresses would not result in rapid piping failure; i.e., pipe breaks.

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*The current construction permit holders for Seabrook Station are: Bangor Hydro-Electric Company, Canal Electric Company, Central Maine Power Company, Central Vermont Public Service Corporation, Connecticut Light & Power Company, Fitchburg Gas & Electric Light Company, Hudson Light & Power Department, Maine Public Service Company, Massachusetts Municipal Wholesale Electric Company, Montaup Electric Company, New England Power Company, New Hampshire Electric Cooperative, Inc., Public Service Company of New Hampshire, Taunton Municipal Lighting Plant, United Illuminating Company, Vermont Electric Generation and Transmission Cooperative, Inc., and Washington Electric Cooperative, Inc.

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Need for Proposed Action: The proposed Exemption is needed because GDC 4 requires that structures, systems and components important to safety shall be appropriately protected against dynamic effects including the effects of discharging fluids that may result from equipment failures, up to and including a double-ended rupture of the largest pipe in the reactor coolant system (Definition of LOCA). In recent submittals the applicants have provided information to show by advanced fracture mechanics techniques that the detection of small flaws by either inservice inspection or leakage monitoring systems is assured long before flaws in the piping materials can grow to critical or unstable sizes which could lead to large break areas such as the double-ended guillotine break or its equivalent. The NRC staff has reviewed and accepted the applicants' conclusion. Therefore, the NRC staff agrees that the double-ended guillotine break in the primary pressure coolant loop piping need not be required as a design basis accident for pipe whip restraints and jet shields, and their associated dynamic effects, i.e., the restraints and jet shields are not needed. Accordingly, the NRC staff agrees that a partial exemption from GDC 4 is appropriate.

Environmental Impact of the Proposed Action: The proposed exemption would not affect the environmental impact of the facility. No credit is given for the barriers to be eliminated in calculating accident doses to the environment. While the jet impingement barriers would minimize the damage from jet forces from a broken pipe, the calculated limitation on stresses required to support the Exemption assure that the probability of pipe breaks which could give rise to such forces are extremely small; thus, the pipe whip restraints and jet shields would have no significant effect on the overall plant accident risk.

The Exemption does not otherwise affect radiological plant effluents. Likewise, the relief granted does not affect non-radiological plant effluents, and has no other environmental impact. The elimination of the pipe whip restraints and jet impingement shields would tend to lessen the occupational doses to workers inside containment. Therefore, the Commission concludes that there are no significant radiological or non-radiological impacts associated with this Exemption.

The proposed Exemption involves design features located entirely within the restricted area as defined in 10 CFR 20. It does not affect plant non-radioactive effluents and has no other environmental impact. Therefore, the Commission concludes that there are no non-radiological impacts associated with the proposed Exemption.

Since we have concluded that there are no measurable negative environmental impacts associated with the Exemption, any alternatives would not provide any significant additional protection of the environment. The alternative to the compliance would be to require literal compliance with GDC 4.

Alternative Use of Resources: This action does not involve the use of resources not previously considered in the Final Environmental Statement (operating license) for Seabrook Units 1 and 2.

Agencies and Persons Contacted: The NRC staff reviewed the applicants' request and applicable documents referenced therein that support the Exemption for Seabrook Units 1 and 2. The NRC did not consult other agencies or persons.

## FINDING OF NO SIGNIFICANT IMPACT

The Commission has determined not to prepare an environmental impact statement for this action. Based upon the environmental assessment, we conclude that this action will not have a significant effect on the quality of the human environment.

For details with respect to this action, refer to the applicants' request for exemption dated August 9, 1984, February 1, 1985 and July 10, 1985. These documents, utilized in the NRC staff's technical evaluation of the exemption request, are available for public inspection at the Commission's Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555, and at the Exeter Public Library, Front Street, Exeter, New Hampshire 03833. The staff's technical evaluation of the exemption request will be published with the exemption (if the exemption is granted) and will also be available for inspection at both locations listed above.

Dated at Bethesda, Maryland, this 12th day of November, 1985.

FOR THE NUCLEAR REGULATORY COMMISSION

Thomas M. Novak, Assistant Director
for Licensing
Division of Licensing

# APPENDIX L

# CONFORMANCE TO REGULATORY GUIDE 1.97, SEABROOK STATION, UNIT NOS. 1 AND 2

EGG-NTA-7256

# CONFORMANCE TO REGULATORY GUIDE 1.97
# SEABROOK STATION, UNIT NOS. 1 AND 2

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## ABSTRACT

This EG&G Idaho, Inc., report reviews the submittal for Regulatory Guide 1.97, Revision 3, for the Seabrook Station, Unit Nos. 1 and 2, and identifies areas of nonconformance to the regulatory guide. Exceptions to Regulatory Guide 1.97 are evaluated and those areas where sufficient basis for acceptability is not provided are identified.

## FOREWORD

This report is supplied as part of the "Program for Evaluating Licensee/Applicant Conformance to RG 1.97," being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A, by EG&G Idaho, Inc., NRR and I&E Support Branch.

The U.S. Nuclear Regulatory Commission funded the work under authorization B&R 20-19-40-41-3.

Docket Nos. 50-443 and 50-444

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# CONFORMANCE TO REGULATORY GUIDE 1.97
# SEABROOK STATION, UNIT NOS. 1 AND 2

## 1. INTRODUCTION

On December 17, 1982, Generic Letter No. 82-33 (Reference 1) was issued by D. G. Eisenhut, Director of the Division of Licensing, Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses and holders of construction permits. This letter included additional clarification regarding Regulatory Guide 1.97, Revision 2 (Reference 2), relating to the requirements for emergency response capability. These requirements have been published as Supplement No. 1 to NUREG-0737, "TMI Action Plan Requirements" (Reference 3).

Public Service of New Hampshire, the applicant for the Seabrook Station, provided a response to Section 6.2 of the generic letter on August 30, 1985 (Reference 4). This response addresses Revision 3 of Regulatory Guide 1.97 (Reference 5).

This report provides an evaluation of that material.

## 2. REVIEW REQUIREMENTS

Section 6.2 of NUREG-0737, Supplement No. 1, sets forth the documentation to be submitted in a report to the NRC describing how the applicant complies with Regulatory Guide 1.97 as applied to emergency response facilities. The submittal should include documentation that provides the following information for each variable shown in the applicable table of Regulatory Guide 1.97.

1. Instrument range
2. Environmental qualification
3. Seismic qualification
4. Quality assurance
5. Redundance and sensor location
6. Power supply
7. Location of display
8. Schedule of installation or upgrade

The submittal should identify deviations from the regulatory guide and provide supporting justification or alternatives.

Subsequent to the issuance of the generic letter, the NRC held regional meetings in February and March 1983, to answer licensee and applicant questions and concerns regarding the NRC policy on this matter. At these meetings, it was noted that the NRC review would only address exceptions taken to Regulatory Guide 1.97. Where licensees or applicants explicitly state that instrument systems conform to the regulatory guide, it was noted that no further staff review would be necessary. Therefore, this report only addresses exceptions to Regulatory Guide 1.97. The following evaluation is an audit of the applicant's submittal based on the review policy described in the NRC regional meetings.

## 3. EVALUATION

The applicant provided a response to Item 6.2 of NRC Generic Letter 82-33 on August 30, 1985. The response describes the applicant's position on post-accident monitoring instrumentation. This evaluation is based on that material.

### 3.1 Adherence to Regulatory Guide 1.97

The applicant has provided a review of their post-accident monitoring instrumentation that compares the instrumentation characteristics against the recommendations of Regulatory Guide 1.97, Revision 3. The applicant states that in several instances, satisfactory instrumentation exists and that additional instrumentation will be installed to comply with Regulatory Guide 1.97, except for those instances where deviations are technically justified. The applicant states that those modifications identified will be completed prior to fuel load. Therefore, we conclude that the applicant has provided an explicit commitment on conformance to Regulatory Guide 1.97, except for those deviations that were justified by the applicant as noted in Section 3.3.

### 3.2 Type A Variables

Regulatory Guide 1.97 does not specifically identify Type A variables, i.e., those variables that provide information required to permit the control room operator to take specific manually controlled safety actions. The applicant classifies the following instrumentation as Type A.

1. Degrees of subcooling

2. Steam generator pressure

3. Core exit temperature

4. Steam generator level

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5. Pressurizer level

6. Refueling water storage tank level

7. Reactor coolant system pressure

8. Containment hydrogen concentration

These variables meet the Category 1 requirements consistent with the requirements for Type A variables, except as noted in Section 3.3.

## 3.3 Exceptions to Regulatory Guide 1.97

The applicant identified the following deviations and exceptions to Regulatory Guide 1.97. These are discussed in the following paragraphs.

### 3.3.1 RCS Cold Leg Water Temperature
### RCS Hot Leg Water Temperature

Regulatory Guide 1.97 recommends Category 1 instrumentation for these variables. As such, channels should be independent and redundant. The applicant's instrumentation is redundant; however, the channels for the cold leg water temperature are powered by one power source, and the channels for the hot leg water temperature are powered by another power source.

The power sources are uninterruptable power supplies (UPS) that are backed by battery and by diesel generator. The hot leg temperature instrumentation is powered by one UPS, the cold leg temperature instrumentation is powered by a second UPS. Diverse instrumentation (core exit temperature and steam generator pressure) are powered by additional UPS power sources. These power sources were previously reviewed by the NRC and found acceptable. We find this to be a good faith attempt, as defined in NUREG-0737, Supplement No. 1, Section 3.7 (Reference 3) to meet NRC requirements and is, therefore, acceptable.

### 3.3.2 Containment Sump Water Level

The applicant is not supplying narrow range instruments specifically for this variable. The narrow range instrumentation is stated to meet the guidance of Regulatory Guide 1.45 and NUREG-0737, Item II.F.1. The applicant states that abnormal leakage is detected with this instrumentation when the leakage is insufficient to actuate the engineered safety features system and it is not monitored by accident procedures.

The Category 1 wide range instruments cover the entire range of expected water levels for post-accident conditions. Based on this, we conclude that (a) the range is sufficient to monitor the sump operation for any anticipated condition and (b) the sump level is adequately monitored by the existing instrumentation. Therefore, we find that the instrumentation provided for this variable is acceptable.

### 3.3.3 Containment Isolation Valve Position

From the information provided, we find that the applicant deviates from a strict interpretation of the Category 1 redundancy recommendation. Only the active valves have position indication (i.e., check valves have no position indication). Since redundant isolation valves are provided, we find that redundant indication per valve is not intended by the regulatory guide. Position indication of check valves is specifically excluded by Table 3 of Regulatory Guide 1.97. Therefore, we find that the instrumentation for this variable is acceptable.

### 3.3.4 Radiation Level in Circulating Primary Coolant

The applicant indicates that radiation level measurements to indicate fuel cladding failure are provided by the post-accident sampling system, that is being reviewed by the NRC as part of their review of NUREG-0737, Item II.B.3.

Based on the alternate instrumentation provided by the applicant, we conclude that the instrumentation supplied for this variable is adequate and, therefore, acceptable.

### 3.3.5 Effluent Radioactivity - Noble Gases

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of $10^{-6}$ to $10^{3}$ µCi/cc. The applicant notes a deviation from the recommended range in that the first instrument that the effluent is monitored by has a range of $10^{1}$ to $10^{6}$ cpm (or $6 \times 10^{-4}$ to 10 µCi/cc). The effluent is then routed to the main plant vent stack, where it is monitored over the range of $10^{-7}$ to $10^{5}$ µCi/cc prior to discharge into the atmosphere. We find the provided instrumentation acceptable for the post-accident effluent flow path.

### 3.3.6 Residual Heat Removal Heat Exchanger Outlet Temperature

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 40 to 350°F. The applicant's instrumentation has a range of 50 to 400°F. The deviation in the lower limit of the range is 10° or 2.5 percent of the upper limit of the range.

The applicant states that the residual heat removal system is cooled by the component cooling water, which is automatically held at 85°F, and alarmed if the temperature drops to 75°F. The applicant states that this gives the operator sufficient time to correct any defect prior to the temperature falling to 60°F.

Based on the applicant's justification, we find this range adequate to monitor this variable during post-accident conditions.

### 3.3.7 Accumulator Level and Pressure

Regulatory Guide 1.97 recommends Category 2 instrumentation to monitor the status of the accumulators. A range of 10 to 90 percent level and 0 to 750 psig is recommended. The applicant has not identified instrumentation for this variable.

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The applicant states that if the accumulators do not perform their intended safety function, there is nothing the operator can do to correct the situation, assuming the accumulator isolation valves are open (these valves are monitored in accordance with the regulatory guide). The only operator action relative to the accumulators in an accident situation is to isolate them. Isolation, regardless of accumulator discharge, is determined by the reactor coolant system (RCS) subcooling being greater than 80°F, and RCS hot leg temperature being less than 400°F. If an isolation valve fails to shut, the operator then opens an accumulator vent valve. The position of these valves is monitored by Category 2 instrumentation.

The applicant has not provided the information required by Section 6.2 of Supplement No. 1 of NUREG-0737 for this variable. An environmentally qualified instrument is necessary to monitor the status of these tanks. The applicant should designate either level or pressure as the key variable to directly indicate accumulator discharge and provide Category 2 instrumentation that meets the recommended range for that variable.

The applicant should provide the required information, identify any deviation from Regulatory Guide 1.97 and provide supporting justification for those deviations.

### 3.3.8 Refueling Water Storage Tank Level

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from top to bottom. The applicant's instrumentation has a range of 22,000 to 485,500 gallons. The applicant states that this range covers the usable volume of the tank. The deviation in 22,000 gallons from the bottom of the tank is 4.5 percent of the total tank volume.

We find this deviation minor with respect to the overall size of the tank. The instrumentation is adequate to monitor the operation of the storage tank during all accident and post-accident conditions. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

### 3.3.9 Pressurizer Level

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from top to bottom. The applicant's instrumentation for this variable has a range of 61.75 to 581.25 inches (approximately 10 to 94 percent of the pressurizer volume). It does not indicate the volume in the hemispherical ends of the vessel.

Outside of the supplied instrument range, in the hemispherical vessel ends, the volume to level ratio is not linear (approximately 16 percent of the total volume). We find this deviation minor and, therefore, acceptable.

### 3.3.10 Pressurizer Heater Status

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable that measures electric current. The applicant's instrumentation is Category 2 except for environmental qualification and measures kilowatts of power instead of current.

The kilowatts of power used by the pressurizer heaters has a direct relation to the heater current. Based on our review and judgement, we find this deviation of measuring pressurizer heater input power rather than current acceptable, since the heater power has a known relation to the heater current.

The applicant states that the instrumentation is acceptable because the pressurizer heaters are not required for the mitigation of a design basis accident, and they are not considered safety-related.

Environmental qualification has been clarified by the Environmental Qualification Rule, 10 CFR 50.49. The applicant should therefore provide the required justification for this deviation from Regulatory Guide 1.97 or provide instrumentation that is environmentally qualified in accordance with the provisions of 10 CFR 50.49 and Regulatory Guide 1.97.

### 3.3.11 Quench Tank Temperature

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 50 to 750°F. The applicant's instrumentation has a range of 50 to 250°F. The applicant states that the operators will be aware of this limitation in the temperature measurement, that enveloping any expected temperature is not necessary and that the range is adequate to indicate off normal conditions.

The applicant has not provided adequate justification for this deviation. The applicant should show that the temperature indication will remain functional and on-scale, including the maximum expected saturation temperature, during any accident that lifts the pressurizer relief valves.

### 3.3.12 Steam Generator Level

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from the tube sheet to the separators. The applicant's instrumentation has a range from 22 inches above the tube sheet to above the separators.

The steam generator is essentially empty when the water is at 22 inches above the tube sheet. Therefore, this deviation is minor with respect to the overall range and system accuracy. The existing range is adequate to monitor this variable during all accident and post-accident conditions.

### 3.3.13 Steam Generator Pressure

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from 0 to 20 percent above the lowest safety valve setpoint (0 to 1425 psig). The applicant's instrumentation has a range of 0 to 1300 psig.

The applicant states that the setpoint of the lowest setting safety valve is 1185 psig, and that the setpoint of the highest setting safety valve is 1255 psig. Thus, there is a margin of 3.6 percent above the setpoint of the highest setting safety valve before the range would be exceeded. The safety valves together can handle the entire steam flow at full reactor power.

Based on the applicant's justification, we find the existing range adequate to monitor the steam generator pressure during all accident and post-accident conditions. Therefore, this is an acceptable deviation from Regulatory Guide 1.97. In addition, each steam generator has a Category 3 channel of instrumentation with a range of 0 to 1500 psig.

### 3.3.14 Containment Spray Flow

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 0 to 110 percent of design flow. The applicant has instrumentation to monitor the operation of the containment spray system that consists of pump suction pressure (0 to 60 psig) and pump discharge pressure (0 to 500 psig). These indicators are located next to each other on the main control board. The applicant states that actual flow measurement is not needed in support of the emergency response procedures, and that the operators will be trained in the use of this instrumentation to verify operation of the containment spray.

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The applicant has alternate instrumentation, consisting of pump suction pressure and pump discharge pressure. Additionally, the effectiveness of the containment spray can be shown by the containment temperature and pressure trends.

The alternate instrumentation provided by the applicant is adequate to monitor this variable. Therefore, we find this deviation acceptable.

### 3.3.15 Heat Removal by the Containment Fan Heat Removal System

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable. The applicant states that this is not considered accident monitoring instrumentation because the containment fan coolers are not required to mitigate design basis events, nor do the emergency response procedures require the operator to monitor their operation.

The applicant states that the containment air coolers are not used in accident and post-accident conditions. Therefore, post-accident monitoring is not provided. We find that this position is acceptable for this variable.

### 3.3.16 Containment Atmosphere Temperature

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 40 to 400°F. The applicant's instrumentation has a range of 50 to 420°F. The applicant states that the containment air temperature will be greater than 50°F during or after any accident.

As the temperature will remain on scale for any accident or post-accident condition, we find the range of 50 to 420°F adequate to monitor this variable.

### 3.3.17 Containment Sump Water Temperature

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable with a range of 50 to 250°F. The applicant states that the emergency response procedures do not require the operator to observe this variable.

This is insufficient justification for this exception. The applicant should provide the recommended instrumentation for the functions outlined in Regulatory Guide 1.97 or identify other instruments (i.e., residual heat removal (RHR) heat exchanger inlet temperature) that provide the same information and satisfy the recommendations of the regulatory guide.

### 3.3.18 Makeup Flow-In
### Letdown Flow-Out

Regulatory Guide 1.97 recommends Category 2 instrumentation for these variables. The applicant has Category 3 instrumentation, stating that this instrumentation is not part of a safety system, and not required in the mitigation of a design basis accident.

As these variables are not utilized in conjunction with a safety system, we find that the instrumentation provided is acceptable.

### 3.3.19 Volume Control Tank Level

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable with a range from top to bottom. The applicant has Category 3 instrumentation that covers the 80 inch straight shell height, not including the hemispherical ends of the tank.

The applicant states that this variable would only be used if letdown and makeup are reestablished following the containment isolation and that the volume control system is not a safety system. The level is not monitored in the hemispherical ends of the tank because the volume to level ratio is non-linear.

As this variable is not utilized in conjunction with a safety system, we find that the Category 3 instrumentation is acceptable. Outside of the supplied instrument range, the volume to level ratio is not linear. We find this deviation minor and, therefore, acceptable.

### 3.3.20 Component Cooling Water Temperature to Engineered Safety Feature System

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from 40 to 200°F. The applicant's instrumentation has a range of 0 to 175°F. The applicant justifies this deviation by stating that the maximum design component cooling water temperature under accident conditions is 120°F.

We find this deviation acceptable. The existing range is capable of indicating any expected accident or post-accident temperature for this variable.

### 3.3.21 High Level Radioactive Liquid Tank Level

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from the top to the bottom of the tank. The applicant's instrumentation covers a range of the top fourteen feet of the tank rather than the eighteen foot tank height. The applicant states that the bottom 4 feet of the tank is a hemispherical bottom section, where the volume to level ratio is not linear.

This range is adequate to indicate the storage volume of the tank during all accident and post-accident conditions. Therefore, this deviation is acceptable.

### 3.3.22 Radioactive Gas Holdup Tank Pressure

Regulatory Guide 1.97 recommends instrumentation for this variable. The Seabrook Station does not have radioactive gas holdup tanks, using carbon delay beds instead. Thus, instrumentation for this variable is not needed.

### 3.3.23 Vent From Steam Generator Safety Relief Valves - Noble Gas

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of $10^{-1}$ to $10^{3}$ µCi/cc. The applicant's instrumentation reads out a range of 1 to $10^{5}$ mR/hr. An offsite dose assessment procedure converts this readout to the equivalent µCi/cc. The safety relief valve position is used to determine the duration of the release for use in this same procedure.

We find the instrumentation provided for this variable acceptable to provide release assessment.

### 3.3.24 Accident Sampling (Primary Coolant, Containment Air and Sump)

The applicant's post-accident sampling system provides sampling and analysis as recommended by the regulatory guide, except for the dissolved oxygen content of the primary coolant and sump contents. The applicant states that Criterion 4 of NUREG-0737, Item II.B.3 recommends this parameter, but does not make it mandatory.

The applicant deviates from Regulatory Guide 1.97 with respect to post-accident sampling capability. This deviation goes beyond the scope of this review and is being addressed by the NRC as part of their review of NUREG-0737, Item II.B.3.

### 3.3.25 Boric Acid Charging Flow

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable. In Amendment 57 to the Final Safety Analysis Report (FSAR), the

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applicant identifies Category 3 instrumentation. No justification was given.

The applicant should either upgrade this instrumentation to Category 2 or justify the use of the existing instrumentation.

## 4. CONCLUSIONS

Based on our review, we find that the applicant either conforms to or is justified in deviating from Regulatory Guide 1.97, with the following exceptions:

1. Accumulator level and pressure--the applicant should designate either level or pressure as the key variable, provide Category 2 instrumentation for that variable, provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737, identify any deviations and justify those deviations (Section 3.3.7).

2. Pressurizer heater status--the applicant should verify that this instrumentation has been addressed in accordance with 10 CFR 50.49 (Section 3.3.10).

3. Quench tank temperature--the applicant should show that the indication will remain functional and on scale during any accident that lifts the pressurizer relief valves (Section 3.3.11).

4. Containment sump water temperature--the applicant should provide the recommended instrumentation or identify alternate instrumentation that provides the same information and satisfies the regulatory guide (Section 3.3.17).

5. Boric acid charging flow--the applicant should either provide Category 2 instrumentation for this variable or justify the use of the present instrumentation (Section 3.3.25).

## 5. REFERENCES

1. NRC letter, D. G. Eisenhut to All Licensees of Operating Reactors, Applicants for Operating Licenses and Holders of Construction Permits, "Supplement No. 1 to NUREG-0737--Requirements for Emergency Response Capability (Generic Letter No. 82-33)," December 17, 1982.

2. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Regulatory Guide 1.97, Revision 2, NRC, Office of Standards Development, December 1980.

3. Clarification of TMI Action Plan Requirements, Requirements for Emergency Response Capability, NUREG-0737, Supplement No. 1, NRC, Office of Nuclear Reactor Regulation, January 1983.

4. Public Service of New Hampshire, New Hampshire Yankee Division letter, J. DeVincentis to G. W. Knighton, NRC, "Accident Monitoring Instrumentation Review and Compliance with Regulatory Guide 1.97," August 30, 1985, SBN-864, T. F. B7.1.2.

5. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Regulatory Guide 1.97, Revision 3, NRC, Office of Nuclear Regulatory Research, May 1983.

# APPENDIX M

# PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

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# PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

## I. INTRODUCTION

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permit was issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice examination requirements set forth in editions and addenda of Section XI of the ASME Boiler and Pressure Vessel Code applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In a submittal dated May 28, 1986, the Applicant requested relief from ASME Code Section XI requirements which he has determined to be impractical to perform at Seabrook Station Unit 1. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing this submittal to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements were justified.

## II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for Seabrook Nuclear Power Station, Unit 1, was issued on July 7, 1976. In accordance with 10 CFR 50.55a(g)(3), components (including supports), which are classified as ASME Code Class 1 and 2, have been designed and provided with access to enable the performance of required preservice examinations.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically examined (radiographed) and the system was subjected to hydrostatic pressure tests.

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examination can then be compared with the original condition to determine whether changes have occurred. If the inservice inspection results show no change from the original

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condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of the preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of Seabrook Nuclear Power Station Unit 1, a large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric examination is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be monitored. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

Several of the preservice inspection relief requests involve limitations to the examination of the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic service-induced degradation. In the event that the welds identified in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the Applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

## III EVALUATION OF RELIEF REQUESTS

The Applicant requested relief from specific preservice inspection requirements in a submittal dated May 28, 1986. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Based on the information submitted by the Applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice inspection requirements of the ASME Boiler and Pressure Vessel Code, Section XI have been determined to be impractical to perform. The Applicant has demonstrated that either (i) the proposed alternative would provide an acceptable level of quality and safety or (ii) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1977 Edition including Addenda through Summer 1978.

### A. Relief Request PR-1, Examination Category B-A, Reactor Pressure Vessel Welds, and Examination Category B-D, Reactor Pressure Vessel Nozzle Full Penetration Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-A, Items B1.11, B1.12, B1.21, B1.22, and B1.30, and Examination Category B-D, Item B3.90 require a 100% volumetric examination of the RPV shell, head, shell-to-flange, and nozzle-to-vessel welds.

Code Relief Request: Relief is requested from performing 100% of the Code and/or Regulatory Guide 1.150-required volumetric examination on the 4 shell welds, 8 head welds, 1 shell-to-flange weld and 8 nozzle-to-vessel welds (21 welds total) listed in Table 1 of Relief Request PR-1.

Reason for Relief: Geometric configuration and permanent obstructions prohibit 100% volumetric examination of the Code-required volume of the subject welds.

Staff Evaluation: The staff has reviewed the Applicant's May 28, 1986 submittal including the attached Table and Figures. In the attached Table 1, the Applicant identified the individual welds with respect to the percentage of the ASME Code Section XI required examination completed, the percentage of the Regulatory Guide 1.150 required examination completed, and provided a description of the obstructions (i.e., nozzle obstruction, weld geometry, control rod drive interference, etc.) encountered during these examinations. The Figures, included in Relief Request PR-1, showed the subject welds with respect to the obstructions encountered. The Applicant reported that all of the subject welds received the ASME Code Section III volumetric and surface examinations during fabrication as well as the construction hydrostatic test.

On the basis of this review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that the reactor vessel would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI and Regulatory Guide 1.150 volumetric examinations in conjunction with the Section III fabrication examinations and hydrostatic tests provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

### B. Relief Request PR-2, Pressurizer and Steam Generator Welds, Examination Category B-B, Pressure Retaining Welds in Vessels, and Examination Category B-D, Full Penetration Welds on Nozzles in Vessels

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-B, Items B2.11 and B2.40, and Examination Category B-D, Items B3.30, B3.40, and B3.50 all require a 100% volumetric examination for PSI.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the 3 pressurizer circumferential shell-to-head welds, 4 steam generator tubesheet-to-head welds, 6 pressurizer nozzle-to-vessel welds, 1 pressurizer nozzle inside radius section, and 8 steam generator nozzle-to-vessel welds (22 items total) identified in Table 1 of Relief Request PR-2.

Reason for Relief: The Applicant reports that geometric configuration and permanent obstructions (i.e. vessel penetrations and steam generator supports) prohibit performance of a 100% volumetric examination of each of the subject welds.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including Table 1 identifying the items for which relief is being requested. This Table includes the component or weld identification, the Code Item Number, the examination angle and technique being used, the configuration of the item, and the percent of the Code-required volume that was completed. The staff notes that each item received at least 74% of the Code-required volumetric examination for PSI. In addition, the Applicant reports that all of the subject welds received the ASME Code Section III volumetric and surface examination during fabrication as well as the construction hydrostatic test. The inservice system leakage tests will be performed per the Code Section XI requirements during each refueling outage.

On the basis of this review, the staff has concluded that a significant percentage of the Code-required examination has been performed and that these components would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI volumetric examinations and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

C. Relief Request PR-3, Examination Category B-J, Reactor Coolant Pump Discharge Nozzle-to-Piping Welds (4 welds)

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-J, Item No. B9.11 requires a 100% surface and volumetric examination for PSI on pressure retaining welds in Class 1 piping of 4 inch nominal pipe size and greater.

Code Relief Request: Relief is requested from performing the Code-required preservice volumetric examination on the 4 Reactor Coolant Pump discharge nozzle-to-piping welds listed in Table 1 of relief request PR-6.

Reason for Request: Due to the construction configuration of these welds, it is not possible to verify complete coverage of the Code-required volume. Each weld consists of a cast stainless steel pump casing (SA-351, CF8A) welded to a wrought stainless pipe (SA-376, TP-304N). In order to provide a satisfactory transition taper between the pump and piping, the pipe side was overlaid with weld material.

Staff Evaluation: The staff has reviewed the Applicant's May 28, 1986 submittal including the attached dimensional drawing of the pump-to-pipe weld with the weld overlay. During the April 15, 1986 Seabrook plant site visit, the staff also had the opportunity to see the subject welds and discuss the difficulties of examination. The Applicant reported that these welds were scanned using a 41° refracted longitudinal (RL) wave from both sides of the weld and that due to the taper of the pump nozzle the resulting angle in the material was essentially 0° relative to the I.D. surface when using the 41° RL fixture on the pump side. This was confirmed during the examination by the presence of a strong backwall signal. The Applicant also reported that the pipe side of each weld was scanned using a 45° shear wave. Due to the metallurgical structure of the weld overlay on the pipe and the effect this type of material typically has on shear waves combined with the existence of a weld material/base material interface parallel to the I.D., the angle of the shear wave in the material and resultant coverage could not be determined. Both sides of the welds were completely scanned with 0° longitudinal beams.

In addition to the above, the subject welds received the ASME Code Section III volumetric and surface examinations during fabrication, as well as the construction hydrostatic test. The inservice system leakage tests will be performed per the Section XI Code requirements during each refueling outage.

Based on the above review, the staff has concluded that the Section III fabrication examinations, supplemented by the Section XI surface examination and the limited Section XI volumetric examination, is equivalent to the required preservice examination and therefore provides an acceptable level of quality and safety.

The staff will continue to monitor the development of new or improved examination techniques. As improvements in these areas are achieved,

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the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

D. Relief Request PR-4, Examination Category B-J, Class 1 Pressure Retaining Welds in Piping, and Examination Category B-F, Pressure Retaining Dissimilar Metal Welds

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-J, Item Nos. B9.11 and B9.31, and Examination Category B-F, Items No. B5.10 and B5.30 all require a 100% surface and volumetric examination for PSI.

Code Relief Request: Relief is requested from performing the preservice volumetric examination of the inaccessible portions of the 19 reactor coolant loop piping circumferential welds (Item No. B9.11), 9 branch connection welds in the reactor coolant loop piping (Item No. B9.31), 1 reactor pressure vessel nozzle-to-safe end weld (Item No. B5.10), and 8 steam generator nozzle-to-safe end welds (Item No. B5.30) listed in Table 1 of PR-4 (37 welds total).

Reason for Request: Geometric configuration, permanent obstructions, and structural interferences prohibit 100% of the Code-required volumetric examination on the subject welds.

Staff Evaluation: The staff has reviewed the Applicant's submittal of Relief Request PR-4, including the attached Table 1 which identifies the individual welds with respect to the percentage of the ASME Code Section XI required volumetric examination completed and the examination technique being used. (See Section 5.2.4.3 of this Supplement for a discussion of the ultrasonic examination techniques used for the examination of the statically cast stainless steel fittings.)

The Applicant also reports that complete examinations which met the requirements of ASME Section XI were performed on welds of similar configuration using the same inspection techniques, equipment, and procedures as those partially inspected or uninspected welds. Since the partially inspected or uninspected welds will see the same operating and environmental conditions as the inspected welds, reasonable assurance of the structural integrity of the welds for which relief is requested has been attained. Also, all of the subject welds received the ASME Code Section III volumetric and surface examination during fabrication as well as the construction hydrostatic test.

Based on the above review, the staff has concluded that the Section III fabrication examinations, supplemented by the Section XI surface examination and the limited Section XI volumetric examination, provides an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

## E. Relief Request PR-5, Examination Categories B-L-2 and B-M-2, Class 1 Pump Casings and Valve Bodies

Code Requirement: Section XI, Table IWB-2500-1, Examination Categories B-L-2 and B-M-2, Item Nos. B12.20 and B12.40, requires a visual (VT-1) examination of valve bodies exceeding 4 inch nominal pipe size (NPS) and of pump casings.

Code Relief Request: For the reactor coolant pump casings and 33 valve bodies in the reactor coolant, pressurizer, safety injection, and residual heat removal systems, relief is requested from disassembly of an operable valve or pump to perform a preservice visual (VT-1) examination.

Reason for Relief: The Applicant reports the following: The requirement to disassemble an operable valve or pump for the sole purpose of performing a visual examination of the internal pressure retaining boundary is impractical and not commensurate to the increased assurance of safety achieved by the inspection. Class 1 valves and pumps are installed in their respective systems and all active valves completed functional testing in accordance with ASME Section XI, Article IWV. To disassemble these items would provide a very small potential for increasing plant safety margins with a disproportionate impact on expenditures of plant manpower and resources. In addition, the Applicant has reported that the manufacturer's test data will be used in lieu of the preservice visual examination. This includes documentation of examinations performed during fabrication and installation of the subject valves. The examinations performed include volumetric, surface, and visual examinations, as required by ASME Section II, Material Specifications for Ferrous and Nonferrous Materials, and ASME Section III, Construction and Installation Requirements. These valves and pumps have been found acceptable by the manufacturer, the ASME Authorized Nuclear Inspector, and New Hampshire Yankee's Quality Assurance.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including Table 1 identifying the items for which relief is being requested, and determined that disassembly of pumps and valves at this time, for the sole purpose of performing preservice visual examination using qualified personnel, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The staff has concluded that the construction code examinations and tests exceed the requirements for visual examination and, therefore, are an acceptable alternative to the Section XI preservice visual examination.

## F. Relief Request PR-6, Examination Category C-A, Pressure Retaining Welds in Pressure Vessels, and Examination Category C-B, Pressure Retaining Nozzle Welds in Vessels

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-A, Items C1.10, C1.20, and C1.30 requires a 100% volumetric examination on Class 2 pressure vessel welds.

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Section XI, Table IWC-2500-1, Examination Category C-B, Item C2.20 requires a 100% surface and volumetric examination on Class 2 nozzles in vessels over 1/2 inch in nominal thickness.

Code Relief Request: Relief is requested from performing the preservice volumetric examination of the inaccessible portion of the 12 vessel shell circumferential welds, 2 vessel head circumferential welds, 1 vessel tubesheet-to-shell weld, and 7 vessel nozzle welds (22 welds total) listed in Table 1 of Relief Request PR-6. These welds are located in the Steam Generators and the Residual Heat Removal and Letdown Heat Exchangers.

Reason for Relief: Geometric configuration and permanent obstructions prohibit the performance of a 100% volumetric examination of each of the subject welds.

Staff Evaluation: The staff has reviewed the Applicant's submittal, including Table 1 identifying the items for which relief is being requested. This Table includes the weld identification, the Code Item Number, the examination angle and technique being used, the configuration of the weld, and the percentage of the Code-required volumetric examination that was completed. The staff notes that on all welds, with exception of the outlet nozzle inner radius area, a significant portion of the Code-required volumetric examination was completed. In addition, the Applicant reports that all of the subject welds received the ASME Code Section III volumetric and surface examination during fabrication as well as the construction hydrostatic test.

Based on the above, the staff has concluded that a significant percentage of the Code-required examination has been performed and that these components would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited Section XI volumetric examinations and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

### G. Relief Request PR-7, Examination Category C-B, RHR Heat Exchanger Nozzle Welds

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-B, Item No. C2.20 requires a 100% surface and volumetric examination on nozzles in vessels over 1/2 inch in nominal thickness.

Code Relief Request: Relief is requested from performing the preservice ultrasonic examination of the nozzle-to-vessel welds on the tube side waterbox of the RHR Heat Exchanger (2 heat exchangers - 2 nozzles each).

Reason for Relief: Table IWC-2500-1, Examination Category C-B, requires a volumetric examination of nozzle welds in vessels whose thickness exceeds 1/2 inch nominal. The Applicant states that, in the case of the Seabrook RHR Heat Exchangers, the weld geometries for the inlet and outlet nozzles do not have a configuration which can be examined with ultrasonic techniques. Therefore, the preservice volumetric examination requirement will be fulfilled by the construction radiography and ultrasonic examination techniques will be developed such that maximum coverage will be achieved at the first refueling outage.

The Applicant reported that the subject welds received the ASME Code Section III volumetric and surface examinations during fabrication as well as the construction hydrostatic test.

Staff Evaluation: The staff has reviewed the Applicant's request and supporting information including Figure 1 which shows the configuration of the RHR Heat Exchanger nozzle-to-shell welds. Although the Code requires examinations performed during preservice to be conducted under conditions and with equipment and techniques equivalent to those which are expected to be employed for subsequent inservice examinations, the staff's review of the feasibility of examining the nozzle-to-shell welds by ultrasonic techniques concludes that the weld design would not permit complete examination of the required volume and that an examination attempted by conventional ultrasonic techniques would result most likely in data that are difficult to evaluate and are questionable.

The staff considers the volumetric (radiography) and surface examinations as well as the hydrostatic presssure test performed to the requirements of Section III of the ASME Code during construction to be adequate to assure the preservice structural integrity of the RHR Heat Exchanger nozzle-to-shell welds. Imposition of the ultrasonic examination would result in an unnecessary hardship on the Applicant without providing a compensating increase in the level of quality or safety of the component or the plant. However, because it is very likely that the RHR Heat Exchanger nozzle-to-shell weld will not be amenable to examination by radiography during inservice operation, the staff will require that an ultrasonic examination technique be developed and applied during the first refueling outage in order to establish an ultrasonic examination baseline and to identify examination constraints if any exist.

## H. Relief Request PR-8, Examination Category C-F, Pressure Retaining Welds in the Containment Building Spray Piping

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-F, Item No. C5.20 requires a 100% surface and volumetric examination on Class 2 piping welds over 1/2 inch nominal wall thickness.

Code Relief Request: Relief is requested from performing the preservice volumetric and surface examinations on the Containment Building Spray Headers beyond the last downstream valve.

Reason for Relief:

1. The subject lines are normally empty and are required to function only in the unlikely event of a major loss of coolant accident or a main steam line break.
2. The subject lines are not exposed to fluctuating stresses, so that propagation of cracks due to defects in the pipe is unlikely.
3. Spray piping welds are examined by radiography during fabrication, so that large defects that could cause catastrophic failure during system operation would be detected and repaired during fabrication and installation of the piping.
4. This piping contains hundreds of open nozzles so that splits or cracks which do not directly cause catastrophic failure would not have a marked effect on the function of the system.
5. System pressure is low, so that pressure stresses in the piping would be unlikely to cause failure in the presence of small defects.

Staff Evaluation: The staff has reviewed the above information and concluded that this relief request is acceptable for PSI based on ASME Nuclear Code Case N-408, "Alternative Rules for Examination of Class 2 Piping", which exempts CHR system piping of any size beyond the last shutoff valve in open ended portions of piping that do not contain water during normal plant operating conditions. In addition, the preservice structural integrity has been demonstrated by the ASME Code Section III volumetric examinations performed during fabrication.

## I. Relief Request PR-9, Examination Category C-F, Pressure Retaining Class 2 Piping and Piping Branch Connection Welds

Code Requirement: Section XI, Table IWC-2500-1, Examination Category C-F, Item Nos. C5.21 and C5.22 require a 100% surface and volumetric examination on Class 2 pressure retaining piping welds over 1/2 inch nominal wall thickness, Item No. C5.31 requires a 100% surface examination on pressure retaining pipe branch connection welds.

Code Relief Request: Relief is requested from performing 100% of the preservice Code-required volumetric examination on Item Nos. C5.21 and C5.22 welds (2 welds) listed in Table 1 of Relief Request PR-9.

Relief is also requested from performing 100% of the FSAR Augmented Examination commitment (volumetric examination) on the 7 branch connection welds (Item No. C5.31) listed in Table 1 of Relief Request PR-9. The Applicant reports that the Code-required surface examination was completed on these welds.

Reason for Request: Geometric configuration, permanent obstructions and/or structural interferences, prohibit 100% examination coverage of the Code-required volume on 2 welds and 100% examination coverage of the FSAR Augmented Examination volume on 7 welds listed in Table 1 of Relief Request PR-9.

Staff Evaluation: The staff has reviewed the Applicant's submittal including Table 1 which identifies the welds for which relief is being requested, the Code Item Number, the examination angle and technique being used, the configuration of the weld, and the percentage of the Code or FSAR Augmented Examination required volume that was examined. In addition, the Applicant reported that the subject welds received the ASME Code Section III volumetric examination during fabrication and the construction hydrostatic test.

Based on the above, the staff concludes that a significant percentage of the Code or FSAR Augmented Examination-required volumetric examination has been performed and that these components would have to be redesigned in order to complete the remainder. Therefore, the staff concludes that the limited preservice volumetric examinations and the Section III fabrication examinations, along with the hydrostatic test, provide an acceptable level of preservice structural integrity and that compliance with the specific requirements of Section XI would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

## IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI required preservice examinations are impractical. The Applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing Seabrook Nuclear Power Station, Unit 1 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Compliance with all the exact Section XI inspections would require the applicant to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are: the reactor pressure vessel, the reactor coolant pump discharge nozzle, and a number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

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Based on the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

# APPENDIX N

## CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
## SEABROOK UNITS 1 AND 2
## (PHASE I)

EGG-HS-6375

# CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
# SEABROOK UNITS 1 AND 2
## (PHASE I)

Docket Nos. 50-443, 50-444

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# ABSTRACT

The Nuclear Regulatory Commission (NRC) has requested that all nuclear plants either operating or under construction submit a response of consistency with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." EG&G Idaho, Inc., has contracted with the NRC to evaluate the responses of those plants presently under construction. This report contains EG&G's evaluation and recommendations for Seabrook.

# EXECUTIVE SUMMARY

Seabrook is consistent with the guidelines of NUREG-0612. However, consistency is dependent on action in the following area:

- Satisfactory action on Guidelines 2, 3, 4, and 6 has been promised but not completed.

The main report contains recommendations which will aid in making the above items consistent with the appropriate guidelines.

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# CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
## SEABROOK UNITS 1 AND 2
## (PHASE I)

## 1. INTRODUCTION

### 1.1 Purpose of Review

This technical evaluation report documents the EG&G Idaho, Inc., review of general load-handling policy and procedures at Seabrook This evaluation was performed with the objective of assessing conformance to the general load-handling guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" [1], Section 5.1.1.

### 1.2 Generic Background

Generic Technical Activity Task A-36 was established by the U.S. Nuclear Regulatory Commission (NRC) staff to systematically examine staff licensing criteria and the adequacy of measures in effect at operating nuclear power plants to assure the safe handling of heavy loads and to recommend necessary changes to these measures. This activity was initiated by a letter issued by the NRC staff on May 17, 1978 [2], to all power reactor applicants, requesting information concerning the control of heavy loads near spent fuel.

The results of Task A-36 were reported in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The staff's conclusion from this evaluation was that existing measures to control the handling of heavy loads at operating plants, although providing protection from certain potential problems, do not adequately cover the major causes of load-handling accidents and should be upgraded.

In order to upgrade measures for the control of heavy loads, the staff developed a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in NUREG-0612, Article 5.1.1, is to ensure that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The second portion of the staff's objective, achieved through guidelines identified in NUREG-0612, Articles 5.1.2 through 5.1.5, is to ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (a) features are provided, in addition to those required for all load-handling systems, to ensure that the potential for a load drop is extremely small (e.g., a single-failure-proof crane) or (b) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small. Acceptability of accident consequences is quantified in NUREG-0612 into four accident analysis evaluation criteria.

The approach used to develop the staff guidelines for minimizing the potential for a load drop was based on defense in depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to assure reliable operation of the handling system

- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment

- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

Staff guidelines resulting from the foregoing are tabulated in Section 5 of NUREG-0612.

### 1.3 Plant-Specific Background

On December 22, 1980, the NRC issued a letter [3] to the Public Service Company of New Hampshire, the applicant for Seabrook, requesting that the applicant review provisions for handling and control of heavy loads at Seabrook, evaluate these provisions with respect to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance to these guidelines. In September 1982, the Public Service Company of New Hampshire provided the initial response [4] to this request. A revised response [9] was provided by the applicant in May 1983.

# 2. EVALUATION AND RECOMMENDATIONS

## 2.1 Overview

The following sections summarize the Public Service Company of New Hampshire's review of heavy load handling at Seabrook accompanied by EG&G's evaluation, conclusions, and recommendations to the applicant for making the facilities more consistent with the intent of NUREG-0612. The Public Service Company of New Hampshire's review of the facilities does not differentiate between the units, so it is assumed that all units are of identical design. The applicant has indicated the weight of a heavy load for this facility (as defined in NUREG-0612, Article 1.2) as 2000 lbs.

## 2.2 Heavy Load Overhead Handling Systems

This section reviews the applicant's list of overhead handling systems which are subject to the criteria of NUREG-0612 and a review of the justification for excluding overhead handling systems from the above-mentioned list.

### 2.2.1 Scope

> "Report the results of your review of plant arrangements to identify all overhead handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal (taking no credit for any interlocks, technical specifications, operating procedures, or detailed structural analysis) and justify the exclusion of any overhead handling system from your list by verifying that there is sufficient physical separation from any load-impact point and any safety-related component to permit a determination by inspection that no heavy load drop can result in damage to any system or component required for plant shutdown or decay heat removal."

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A. Summary of Applicant's Statements

The applicant's review of overhead handling systems identified the cranes and hoists shown in Table 2.1 as those which handle heavy loads in the vicinity of irradiated fuel or safe shutdown equipment.

The applicant has also identified other cranes that have been excluded from satisfying the criteria of the general guidelines of NUREG-0612.

B. EG&G Evaluation

The applicant appears to have included all applicable handling systems in their tables showing handling systems for which a load drop could damage safety equipment.

C. EG&G Conclusions and Recommendations

Based on the information provided, EG&G concludes that the applicant has included all of the applicable hoists and cranes in their list of handling systems which must comply with the requirements of the general guidelines of NUREG-0612.

## 2.3 General Guidelines

This section addresses the extent to which the applicable handling systems comply with the general guidelines of NUREG-0612 Article 5.1.1. EG&G's conclusions and recommendations are provided in summaries for each guideline.

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TABLE 2.1 CRANE/HOIST SYSTEMS CONSIDERED AS POTENTIAL SOURCES FOR DAMAGE OF SAFETY COMPONENTS

| TAG NO. | HANDLING SYSTEM | CAPACITY | LOCATION |
|---|---|---|---|
| MM-CR-3 | Polar Gantry Crane | 420 Ton Main<br>50 Ton Auxiliary | Containment |
| FH-RE-24 | Radial Arm Stud Tensioner Hoists (3) | 2 Tons | Containment |
| FH-RE-1 | Spent Fuel Cask Handling Crane | 125 Ton Main, Two Auxiliary Hooks at 5 Tons Each | Fuel Storage Building |
| CS-CR-5 | Filter Cask Monorail Hoist | 7.5 Tons | Primary Auxiliary Building |
| CS-CR-6 | Boric Acid Batching Monorail Hoist | 4.5 Tons (2.25T)* | Primary Auxiliary Building |
| CS-CR-13 | CVCS Heat Exchanger Service Monorail Hoist | 5 Tons | Primary Auxiliary Building |
| CS-CR-14A, 14B & 14C | Charging Pump Service Monorail Hoist | 2.5/2.5/6.0 Tons | Primary Auxiliary Building |
| CC-CR-15A & 15B | Component Cooling Water Pump Service Monorail Hoist | 5 Tons | Primary Auxiliary Building |
| CBS-CR-18A & 18B | Radioactive Pipe Tunnel Service Monorail Hoist | 2 Tons | Radioactive Pipe Tunnel |
| MS-CR-25A & 25B | Main Stream and Feedwater Pipe Chase Crane | 7.5 Tons | MS and FW Pipe Chase |
| FW-CR-27 | Emergency Feed Pump Monorail Hoist | 5 Tons | Emergency Feedwater Pump Building |
| DG-CR-28A & 28B | Diesel Generator Service Crane | 8 Tons | Diesel Generator Building |

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* Capacity shown in parentheses is the derated capacity.

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The NRC has established seven general guidelines which must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

- Guideline 1--Safe Load Paths
- Guideline 2--Load-Handling Procedures
- Guideline 3--Crane Operator Training
- Guideline 4--Special Lifting Devices
- Guideline 5--Lifting Devices (Not Specially Designed)
- Guideline 6--Cranes (Inspection, Testing, and Maintenance)
- Guideline 7--Crane Design.

These seven guidelines should be satisfied for all overhead handling systems and programs in order to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent-fuel pool, or in other areas where a load drop may damage safe shutdown systems. The succeeding paragraphs address the guidelines individually.

### 2.3.1 Safe Load Paths [Guideline 1, NUREG-0612, Article 5.1.1(1)]

> "Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent-fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee."

## A. Summary of Applicant's Statements

The applicant has evaluated load path locations for the Seabrook Station.

"Drawings depict the safe travel paths for heavy loads which, if dropped, could impact the irradiated fuel or components in the systems required for shutdown or decay heat removal. Also shown on these layout drawings are the locations of the safety-related equipment and spent fuel, where applicable. To the maximum extent practicable, handling of heavy loads over safety-related equipment is avoided in identifying the safe load paths. Also, in defining these load paths consideration has been given to the safety-related equipment located on lower elevations below the operating floor for the load-handling system in question.

"During the crane operator training program, emphasis will be placed on the need to adhere to these safe load paths. Heavy loads will be moved by the safest and shortest routes in accordance with the approved load-handling procedures and the safe load path drawings. The crane operator will be directed by a signal person using standard signals given in ANSI B30.2-1976 and ANSI B30.11-1980. The signal person will ensure that the load is moved along the designated path; any deviations, if required, will be handled per procedure AQ 1.002, Station Operating Procedures."

## B. EG&G Evaluation

The applicant has developed and shown load paths on layout drawings. They have stated that marking load paths on the floor is not feasible. However, they have stated that the signal person will ensure that the load is moved along the safe load path.

### C. EG&G Conclusions and Recommendations

EG&G concludes from the applicant's response that safe load paths for the Seabrook Station are consistent with the intent of Guideline 1.

## 2.3.2 Load-Handling Procedures [Guideline 2, NUREG-0612, Article 5.1.1(2)]

> "Procedures should be developed to cover load-handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. At a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment; inspections and acceptance criteria required before movement of load; the steps and proper sequence to be followed in handling the load; defining the safe path; and other special precautions."

### A. Summary of Applicant's Statements

The applicant states that procedures will be developed to cover load-handling operations for the heavy loads carried by the handling systems identified in Table 2.1. These procedures will identify the required equipment, the inspection and acceptance criteria prior to load movement, the steps and sequence in handling the load, and define the safe load path and other special precautions. They also state that approved procedures will be in effect prior to use of the load-handling system.

B. EG&G Evaluation

The applicant has stated that load-handling procedures will be developed which will comply with the requirements of Guideline 2.

C. EG&G Conclusions and Recommendations

The Seabrook Station is consistent with Guideline 2 in that procedures will be developed by the applicant to meet the criteria of this guideline. These procedures should be available for possible NRC review prior to use of the load-handling system.

### 2.3.3 Crane Operator Training [Guideline 3, NUREG-0612, Article 5.1.1(3)]

"Crane operators should be trained, qualified, and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, 'Overhead and Gantry Cranes' [5]."

A. Summary of Applicant's Statements

The applicant states that Seabrook Station will be consistent with ANSI B30.2-1976 with respect to operator training, qualification, and conduct.

B. EG&G Evaluation

The applicant is developing a training and qualification program and appears to be implementing the applicable ANSI B30.2 requirements. No information on conduct was given by the applicant other than their statement that they will be consistent with ANSI B30.2-1976. This consistency should be complete before fuel loading occurs.

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C. EG&G Conclusion and Recommendations

Based on the applicant's statement Seabrook Station is consistent with Guideline 3.

### 2.3.4 Special Lifting Devices [Guideline 4, NUREG-0612, Article 5.1.1(4)]

> "Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, 'Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials' [6]. This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants, certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. This is in lieu of the guideline in Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) or the load and of the intervening components of the special handling device."

A. Summary of Applicant's Statements

The various lifting devices employed in handling the heavy loads at Seabrook have been identified by the applicant. Of these devices, the following are categorized as special lifting devices:

1. Reactor Vessel Hand Lifting Rig, Load Cell, and Load Cell Linkage Assembly
2. Internals Lifting Rig, Load Cell, and Load Cell Linkage Assembly
3. Spent Fuel Cask Lifting Device

4. Reactor Coolant Pump Motor Lifting Device

5. Reactor Cavity Seal Ring Lifting Device

6. Equipment Hatch Cover Handling Device

7. Pressurizer Enclosure Wall Handling Device.

The reactor vessel head and internals lifting rigs and associated load cell and linkage assemblies have been evaluated by Westinghouse to verify consistency with the requirements of ANSI N14.6 and NUREG 0612. Conclusions from the Westinghouse evaluation are as follows:

1. The ANSI N14.6 requirements for design, fabrication, and quality assurance are generally in agreement with those used for these special lift devices.

2. The ANSI N14.6 criteria for stress limits associated with certain stress design factors for tensile and shear stresses are adequately satisfied.

3. The application of the ANSI N14.6 criteria for stress design factors are only for shear and tensile loading conditions. Other loading conditions are to be analyzed to other appropriate criteria, and these criteria are satisfied.

4. These devices are not strictly consistent with the ANSI N14.6 requirements for acceptance testing, maintenance and verification of continuing compliance. Alternate equivalent and/or adequate tests and inspection program, as permitted by NUREG 0612, will be implemented that should enable these devices to be considered consistent with the intent of ANSI N14.6.

The design of the spent-fuel cask and lifting device has not yet been finalized. A detailed review of the lifting device will be performed to verify consistency with ANSI N14.6-1978, once the cask design has been selected, and the results of the analysis will be provided to the NRC prior to any cask-handling operations at the plant site.

The reactor coolant pump motor lifting device, reactor cavity seal ring lifting device, equipment hatch cover handling device, and the pressurizer enclosure wall handling device will be consistent with the requirements of ANSI N14.6-1978 and NUREG 0612. The results of the evaluation to be performed to determine consistency with these applicable standards will be made available to the NRC for review, prior to use of these devices with their respective loads. The design of these four special lifting devices has not been finalized.

All special lifting devices will be subjected to periodic testing and inspection to verify continued consistency, in accordance with the provisions of Section 5 of ANSI N14.6-1978 with the following clarifications/exceptions.

1. The tests or inspections as outlined below in (3) will be performed prior to use of the lifting device if it is not used for a period exceeding one year.

2. Where the usage frequency is more than once a year, the tests and inspections will be performed annually.

3. A 100% load test using the actual load plus visual examination of critical welds and parts will be conducted as part of the lift. A periodic nondestructive surface examination of critical welds and/or parts will be performed to ensure continued adequacy.

4. All special lifting devices will be visually inspected by maintenance personnel prior to each use instead of every three months (5.3.7) for indications of damage or deformation.

Alternative load tests and nondestructive examination frequency proposed above are based upon the following considerations:

1. Load testing to 150% of the total weight before each use would require special fixtures and is impractical to perform. Therefore, these special lifting devices will be tested at 100% of the load to be carried. Also, with the use of load cell for the head and internals lift rigs, all lifting and lowering is monitored at all times.

2. Access to the welds for surface examination, for most of these special lift rigs, is difficult as they are stored in containment or fuel storage building and some contamination is present.

3. The items that are welded remain assembled and cannot be used for any other lift other than their intended function. The devices are stored in protected areas, away from adverse environmental conditions and physical abuse that could have detrimental effect on the integrity and reliability of these special lifting devices.

4. Dimensional checking is not included since these structures are large and the results of dimensional measurements would always be questionable, and will not serve any useful purpose.

## B. EG&G Evaluation

The applicant has identified seven special lifting devices.

In EG&G's judgment, Westinghouse's evaluation of two of these devices is consistent with the intent of this guideline and the requirements of ANSI N14.6.

The Westinghouse evaluation showed that in some cases, the stress design factors of ANSI N14.6 are not satisfied. However, the design factors were stated to meet AISC allowables. EG&G feels that for the few cases where ANSI N14.6 stress design factors are not satisfied, a testing and inspection program with special attention to those parts which have a lower safety factor is consistent with the intent of the guideline. Also, procedures to reduce the possibility of impact or dynamic loads should be used for these devices. No information on the other special lifting device was presented other than statements that they will comply with the requirements of this guideline with exceptions as noted in the above summary of the applicant's statements. The 150% load test is not required by ANSI N14.6 except in special cases, although it is an alternate to other nondestructive tests and examinations. In EG&G's view, the testing proposed by the applicant is consistent with the intent of this guideline.

## C. EG&G Conclusions and Recommendations

Seabrook Station is consistent with the intent of the requirements of Guideline 4 and ANSI N14.6-1978 based on the applicant's statements. However, evaluation of consistency with this guideline should be complete for each special lifting device before it is used to lift a heavy load near fuel or safety-related equipment.

### 2.3.5 Lifting Devices (Not Specially Designed) [Guideline 5, NUREG-0612, Article 5.1.1(5)]

"Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, 'Slings' [7]. However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load. The rating identified on the sling should be in terms of the 'static load' which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used."

#### A. Summary of Applicant's Statements

The applicant states that all standard lifting devices will meet the requirements of ANSI B30.9-1971 and Section 5.1.1(5) of NUREG 0612.

#### B. EG&G Evaluation

The applicant indicates that slings used at Seabrook Station will be consistent with the requirements of this guideline.

#### C. EG&G Conclusions and Recommendations

Seabrook Station is consistent with Guideline 5.

### 2.3.6 Cranes (Inspection, Testing, and Maintenance) [Guideline 6, NUREG-0612, Article 5.1.1(6)]

"The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified

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inspection and test frequency (e.g., the polar crane inside a PWR containment may only be used every 12 to 18 months during refueling operations, and is generally not accessible during power operation. ANSI B30.2, however, calls for certain inspections to be performed daily or monthly. For such cranes having limited usage, the inspections, test, and maintenance should be performed prior to their use)."

### A. Summary of Applicant's Statements

A program will be developed to ensure that cranes will be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976. Frequency of tests and inspections will be consistent with Section 5.1.1(6) of NUREG 0612.

### B EG&G Evaluation

The applicant states that crane inspection, testing, and maintenance programs will be consistent with ANSI B30.2-1976 with exceptions as allowed by Guideline 6.

### C. EG&G Conclusions and Recommendations

Seabrook Station is consistent with Guideline 6 on the basis of the applicant's statement.

## 2.3.7 Crane Design [Guideline 7, NUREG-0612, Article 5.1.1(7)]

"The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' and of CMAA-70, 'Specifications for Electric Overhead Traveling Cranes' [8]. An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied."

## A. Summary of Applicant's Statements

The polar gantry crane and spent fuel cask handling crane were designed in accordance with the CMAA-70 and ANSI B30.2-1967. Monorails and underhung cranes are designed to ANSI B30.11 and B30.16.

## B. EG&G Evaluation

The cranes mentioned by the applicant in their response are consistent with or meet the intent of Guideline 7 based on the applicant's statements.

## C. EG&G Conclusions and Recommendations

Seabrook Station is consistent with Guideline 7 on the basis of the applicant's statements.

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# 3. CONCLUDING SUMMARY

## 3.1 Applicable Load-Handling Systems

The list of cranes and hoists supplied by the applicant as being subject to the provisions of NUREG-0612 is adequate (see Section 2.2.1).

## 3.2 Guideline Recommendations

Consistency with the seven NRC guidelines for heavy load handling (Section 2.3) is partially satisfied at Seabrook Station. This conclusion is represented in tabular form as Table 3.1. Specific recommendations to aid in consistency with the intent of these guidelines are provided as follows:

| Guideline | Recommendation |
|---|---|
| 1. (Section 2.3.1) | a. Seabrook is consistent with this guideline. |
| 2. (Section 2.3.2) | a. Seabrook will be consistent with the guideline after completion of load-handling procedures. |
| 3. (Section 2.3.3) | a. Seabrook is consistent with this guideline. |
| 4. (Section 2.3.4) | a. Seabrook will be consistent with the intent of the guideline after all lifting devices are evaluated with respect to ANSI N14.6. |
| 5. (Section 2.3.5) | a. Seabrook is consistent with this guideline. |
| 6. (Section 2.3.6) | a. Seabrook is consistent with this guideline. |
| 7. (Section 2.3.7) | a. Seabrook is consistent with this guideline. |

## 4. REFERENCES

1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, NRC.
2. V. Stello, Jr. (NRC), Letter to all applicants. Subject: Request for Additional Information on Control of Heavy Loads Near Spent Fuel NRC, 17 May 1978.
3. USNRC, Letter to Public Service Company of New Hampshire. Subject: NRC Request for Additional Information on Control of Heavy Loads Near Spent Fuel NRC, 22 December 1980.
4. Public Service Company of New Hampshire, Letter to Director of Nuclear Regulatory Regulation. Subject: Response to NRC Request for Additional Information on Control of Heavy Loads, September 1982.
5. ANSI B30.2-1976, "Overhead and Gantry Cranes."
6. ANSI N14.6-1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or more for Nuclear Materials."
7. ANSI B30.9-1971, "Slings."
8. CMAA-70, "Specifications for Electric Overhead Traveling Cranes."
9. Public Service Company of New Hampshire, Letter to G. W. Knighton (NRC). Subject: NUREG-0612 Control of Heavy Loads (Revised Report), June 1983.

TABLE 3.1. SEABROOK STATION NUREG-0612 COMPLIANCE MATRIC

| Equipment Designation | Heavy Loads | Weight or Capacity (lbs) | Guideline 1 Safe Load Paths | Guideline 2 Procedures | Guideline 3 Crane Operator Training | Guideline 4 Special Lifting Devices | Guideline 5 Slings | Guideline 6 Crane-Test and Inspection | Guideline 7 Crane Design |
|---|---|---|---|---|---|---|---|---|---|
| | | | C | C | C | -- | -- | C | C |
| Polar Gantry Crane<br>MM-CR-3<br>420 Ton Main<br>50 Ton Auxiliary<br>Whiting Corporation | Neutron Shield Panel (8) | 10,000 each | C | C | -- | -- | C | -- | -- |
| | Reactor Cavity Seal Ring | 18,625 | C | C | -- | -- | C | -- | -- |
| | Reactor Missile Shield and Support (plus CRDM cooling fans) | 40,000 (with spreader assembly | C | C | -- | -- | C | -- | -- |
| | CRDM Cooling Air Duct and Supports Heaviest Section | -- | C | C | -- | -- | C | -- | -- |
| | Reactor Vessel Head and Attachments | 336,218 (with lifting rig) | C | C | -- | C | -- | -- | -- |
| | Internals Lifting Rig | 18,350 | C | C | -- | C | -- | -- | -- |
| | Upper Internals | 152,000 (with lifting rig) | C | C | -- | C | -- | -- | -- |
| | Lower Internals | 340,000 (with lifting rig) | C | C | -- | C | -- | -- | -- |
| | Jib Crane (including hoist and trolley) | 3,000 | C | C | -- | -- | C | -- | -- |
| | Stud Tensioners | 2,500 | C | C | -- | -- | C | -- | -- |

TABLE 3.1. (continued)

| Equipment Designation | Heavy Loads | Weight or Capacity (lbs) | Guideline 1 Safe Load Paths | Guideline 2 Procedures | Guideline 3 Crane Operator Training | Guideline 4 Special Lifting Devices | Guideline 5 Slings | Guideline 6 Crane-Test and Inspection | Guideline 7 Crane Design |
|---|---|---|---|---|---|---|---|---|---|
| | R.V. Head Stud, Nut and Washer Assembly | 700 | C | C | -- | -- | C | -- | -- |
| | RC Pump Motor | 100,260 | C | C | -- | -- | C | -- | -- |
| | RC Pump Motor Support | 9,300 | C | C | -- | -- | C | -- | -- |
| | RC Pump Internals | 44,900 | C | C | -- | -- | C | -- | -- |
| | RC Pump Assembly (including casing) | 94,400 | C | C | -- | -- | C | -- | -- |
| | RC Pump Removable Concrete Plugs (2 sections) | 37,000 (Heaviest) | C | C | -- | -- | C | -- | -- |
| | RC Pump Handling Frame | 10,000 | C | C | -- | -- | C | -- | -- |
| | Plug for In-Core Detector Drive | 10,000 | C | C | -- | -- | C | -- | -- |
| | 420 Ton Hoist Load Block | 30,000 | C | C | -- | -- | C | -- | -- |
| | 50 Ton Hoist Load Block | 2,000 | C | C | -- | -- | -- | -- | -- |
| | Miscellaneous Equipment in Containment Annulus Area | -- | -- | -- | -- | -- | C | -- | -- |
| | Pressurizer Missile Shield (3 Sections) Heaviest Section | 4,000 | C | C | -- | -- | C | -- | -- |
| | Equipment Hatch Cover (including airlock) | 85,150 | C | C | -- | C | -- | -- | -- |
| | Pressurizer Enclosure Wall--Two Removable Panels | 85,000 each | C | C | -- | C | -- | -- | -- |

TABLE 3.1. (continued)

| Equipment Designation | Heavy Loads | Weight or Capacity (lbs) | Guideline 1 Safe Load Paths | Guideline 2 Procedures | Guideline 3 Crane Operator Training | Guideline 4 Special Lifting Devices | Guideline 5 Slings | Guideline 6 Crane-Test and Inspection | Guideline 7 Crane Design |
|---|---|---|---|---|---|---|---|---|---|
| Radial Arm Stud Tensioner Hoists (3) 2 Ton Capacity each | Stud Tensioner RV Head | 2,500 | C | C | -- | -- | C | -- | -- |
| | Stud, Nut and Washer Assembly | 700 | C | C | -- | -- | C | -- | -- |
| | Guide Studs | 650 | C | C | -- | -- | C | -- | -- |
| Spent Fuel Cask Handling Crane | Spent-Fuel Cask | -- | C | C | C | C | -- | C | C |
| FH-RE-1<br>125 Ton Main<br>5 Ton Aux. (2)<br>Whiting Corporation | New-Fuel Shipping Container | 6,700 | C | C | C | -- | C | -- | C |
| | New-Fuel Assembly | 1,700 (with handling tool) | C | -- | -- | -- | -- | -- | -- |
| | Crane Load Block (125 Ton) | 5,900 | C | -- | -- | -- | -- | -- | -- |
| | Irradiated Specimen Cask | -- | C | I | -- | -- | -- | -- | -- |
| | Failed-Fuel Container | -- | C | I | -- | -- | -- | -- | -- |
| Filter Cask Monorail Hoist CS-CR-5 | Filter Cask (CVCS system) | -- | C | C | C | -- | C | C | C |
| 7.5 Ton Capacity | Concrete Floor Plug | 3,000 | C | C | -- | -- | C | -- | -- |
| Boric Acid Batching Monorail Hoist | Hatch Cover (2 sections) | 1,300 each | C | C | C | -- | C | C | C |
| CS-CR-6<br>4.5 Ton Capacity<br>(Derated Capacity--2.25T) | Pallets of Boric Acid | Less than 4,500 | C | C | C | -- | C | C | C |

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TABLE 3.1. (continued)

| Equipment Designation | Heavy Loads | Weight or Capacity (lbs) | Guideline 1 Safe Load Paths | Guideline 2 Procedures | Guideline 3 Crane Operator Training | Guideline 4 Special Lifting Devices | Guideline 5 Slings | Guideline 6 Crane-Test and Inspection | Guideline 7 Crane Design |
|---|---|---|---|---|---|---|---|---|---|
| CVCS Heat Exchanger Service Monorail Hoist CS-CR-13 | Removable Concrete Floor Plug (2 sections) | 5,000 each | C | C | C | -- | C | C | C |
| 5 Ton Capacity (Unit #1 only) | Heat Exchanger Tube Bundle | 2,150 (Heaviest) | C | -- | -- | -- | C | -- | -- |
| Charging Pump Service Monorail Hoist | Charging Pump Components | -- | C | C | C | -- | C | C | C |
| CS-CR-14A, 14B & 14C 2.5/2.5/6.0 Ton Capacity | Charging Pump Motor<br>Gear | 4,905<br>2,700 | C | C | -- | -- | C | -- | -- |
| Component Cooling Water Pump Service Monorail Hoist | Primary Component Cooling Water Pump | 3,600 | C | C | C | -- | C | C | C |
| CC-CR-15A & 15B 5 Ton Capacity each | PCCW Pump Motor | 5,270 | C | C | -- | -- | C | -- | -- |
| Emergency Feed Pump Monorail Hoist | Emergency Feedwater Pump | 5,700 | C | C | C | -- | C | C | C |
| FW-CR-27 5 Ton Capacity | Emergency Feedwater Pump Motor | 4,800 | C | C | -- | -- | C | -- | -- |
| | Emergency Feedwater Pump Turbine | 3,900 | C | C | -- | -- | C | -- | -- |
| | 6 ft-0 in. x 4 ft-6 in. Removable Concrete Floor Plug | 4,000 | C | C | -- | -- | C | -- | -- |
| Diesel Generator Service Crane DG-CR-28A & 28B | Miscellaneous Diesel Generator Components | -- | C | C | C | -- | C | C | C |
| 8 Ton Capacity each | Turbocharger (heaviest anticipated lift) | 2,160 | C | C | -- | -- | C | -- | -- |

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TABLE 3.1. (continued)

| Equipment Designation | Heavy Loads | Weight or Capacity (lbs) | Guideline 1 Safe Load Paths | Guideline 2 Procedures | Guideline 3 Crane Operator Training | Guideline 4 Special Lifting Devices | Guideline 5 Slings | Guideline 6 Crane-Test and Inspection | Guideline 7 Crane Design |
|---|---|---|---|---|---|---|---|---|---|
| Main Steam and Feed-water Pipe Chase Crane MS-CR-25A & 25B 7.5 Ton Capacity each | MS Isolation Valve Assembly | 14,065 | C | C | C | -- | C | C | C |
| | A-260 Actuator | 3,327 | C | C | -- | -- | C | -- | -- |
| | Limitorque Operator | 225 | C | C | -- | -- | C | -- | -- |
| | FW Isolation Valve Assembly | 5,241 | C | C | -- | -- | C | -- | -- |
| | FW Isolation Valve | 4,369 | C | C | -- | -- | C | -- | -- |
| | FW Isolation Valve Operator | 872 | C | C | -- | -- | C | -- | -- |
| RADIOACTIVE PIPE TUNNEL | | | | | | | | | |
| Radioactive Pipe Tunnel Service Monorail Hoist CBS-CR-18A & 18B 2 Ton Capacity each | Encapsulation Vessel Head | 1,000 | C | C | C | -- | C | C | C |
| | Encapsulation Vessel Skirt | 1,200 | C | C | -- | -- | C | -- | -- |
| | Sump Isolation Valve Topworks (16 in. CBS-V8 and V14) | Less than 2,500 | C | C | -- | -- | C | -- | -- |

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C = Applicant action is consistent with NUREG-0612 Guideline.
NC = Applicant action is not consistent with NUREG-0612 Guideline
R = Applicant has proposed revisions/modifications designed to be consistent with NUREG-0612 Guideline.
I = Insufficient information provided by the Applicant.

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# APPENDIX O

# TECHNICAL EVALUATION REPORT
SEABROOK STATION
SER CONFIRMATORY ISSUE NO. 25

# TECHNICAL EVALUATION REPORT

# SEABROOK STATION

# SER CONFIRMATORY ISSUE NO. 25

## I. BACKGROUND

By References (a), (b), and (c), Public Service of New Hampshire (PSNH) forwarded for the staff review, information regarding Items 10 and 11 of the "Study on Electrical Interconnections Between Redundant Divisions." The staff concern in this area centers about the possibility of the inadvertent application of 120 VAC (Train A power source) within equipment cabinets to the field devices (Train B) which provide input signals to the equipment cabinets. The staff requested that test programs be conducted to substantiate the conclusions of the failure mode analysis provided by the applicant which involved the application of the 120 VAC to the field device circuits. The specific tests requested involved application of 120 VAC to the signal processing circuits where low voltage dc power is normally utilized.

Reference (d) forwarded the results of the tests. The test results were separated as follows: Attachment 1 for Item 10 and Attachment 2 for Item 11.

A review of these two attachments resulted in a series of questions generated to clarify the test results. References (e) and (f) forwarded the answers to these questions.

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## II. DISCUSSION

This discussion centers on the information and data contained in Attachments 1 and 2 of Reference (d) that relates to or affects the field devices.

The analysis of the failure modes of the equipment, the types of tests performed on the equipment, the conclusions reached, and the overall philosophy applied to the two attachments are all the same. The difference being in the equipment that is undergoing the analysis and test.

Attachment 1 addresses the interface between Train B associated signal inputs and a Train A associated 120 VAC power supply within the Intelligent Remote Termination Units (IRTU). The digital signal inputs to the IRTU are from relay contacts or changing voltage levels. The analog signal inputs are from transducers that provide a low level voltage or current signal.

Attachment No. 2 addresses the interface between Train B associated signal inputs and a Train A associated 120 VAC power supply within the Resistance Temperature Detector/Thermocouple Conversion Cabinets (RTD/TC-CC). The RTD/TC-CC has only analog input signals that come from RTD's or TC's.

The attachments evaluate the respective equipment in two phases: analysis and test. The analysis phase addressed the types of failure modes such as open circuits, short circuits, shorts to ground, application of the maximum credible voltage failures (MCVF), and technician errors. The test phase was conducted to verify the conclusions reached by the analysis with respect to the application of the MCVF to the low voltage ac and dc circuits (± 12 VAC & DC). The acceptance criteria for the MCVF test is that the Class 1E side with which the field device is associated is not degraded below an acceptable level; that is, it continues to perform its safety function before, during and after the fault.

The analysis demonstrated that an open circuit within the respective equipment would potentially disable the function of the equipment but would not cause any detrimental impact on the field device.

The analysis goes on to show that for short circuits and shorts to ground the faults would be cleared by the multiple protective devices or the potential burning open of components. These actions would result in loss of power to the equipment, but will not cause any detrimental impact on the field devices.

With regard to the application of the MCVF, the analysis again showed that protective devices, surge suppression devices, burned open circuit components and other passive circuit components would limit the fault voltage and current to safe levels. These safe levels of voltage and current will not cause any detrimental impact on the field devices.

The analysis further goes on to state that the inadvertent application of 120 VAC to the untested terminals of the field signal circuits due to mechanical means or technician error is not credible. This statement is based upon the fact that the 120 VAC enters the equipment in areas that do not contain the untested terminals or the field circuits and also that the 120 VAC conductors are run in flexible conduits and that terminations

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are made utilizing splices as opposed to terminal boards in the sensitive areas of the equipment. Also, the multi-conductor signal cables are terminated in multi-pin connectors which have no exposed metal parts.

The second phase covered by the attachments deals with the actual application of the MCVF to those areas of the circuits covered by the analysis phase. The MCVF was determined to be 120 VAC supplied by a device with a 20 amp rating.

The first step in performing the tests was to determine the most sensitive field device (MSFD) since each different type of field device was not subjected to the tests. The field devices selected were determined to be the most sensitive and having the most potential for degradation. In the case of the RTD/TC-CC equipment, it was the RTD's and in the case of the IRTU's it was the G.E. IAV relay for the digital inputs and a Rochester Instrument ac current transducer for the analog inputs.

After selecting the MSFD, the devices were given a pretest functional check. This pretest verified the functional operation of the device and established the normal signal levels. The MCVF of 120 VAC was then applied to the 12 VAC inputs on the RTD/TC-CC's and to the low voltage DC inputs on the IRTU's.

Circuit components in the RTD/TC-CC's suffered no damage upon the application of the MCVF, however, the DC power supply mounted on the circuit board failed. The power supply was potted within an aluminum housing so its failure mode could not be determined. The IRTU cabinets suffered greater amounts of damage in the form of damaged capacitors, resistors, integrated circuits and a damaged multiplexing relay.

Post MCVF functional tests showed that the field devices which were subjected to the MCVF were not degraded below an acceptable level as the post test values in all cases were essentially the same as the pretest valves.

## III. CONCLUSION

Based on the results of the tests, it has been shown that with respect to the field devices faults in the Train A power system will not degrade the Train B field devices. This verifies the analysis. Attachments 1 and 2 are acceptable as they relate to the field devices only and may be used to close out SER Confirmatory Issue No. 25.

## IV. REFERENCES

(a) PSNH Letter (SBN-587), dated December 1, 1983, "Electrical Interconnections Between Redundant Divisions," J. DeVincentis to G. W. Knighton

(b) PSNH Letter (SBN-671), dated June 20, 1984, "Electrical Interconnections Between Redundant Divisions," J. DeVincentis to G. W. Knighton

(c) PSNH Letter (SBN-903), dated November 27, 1985, "Resolution of Power Systems Branch Confirmatory Items," J. DeVincentis to G. W. Knighton

(d) PSNH Letter (SBN-1020), dated April 25, 1986, "Resolution of Power Systems Branch Confirmatory Items: Additional Information (SER Confirmatory Issue No. 25), J. DeVincentis to V. S. Noonan

(e) PSNH Letter (SBN-1066), dated May 23, 1986, "Response to Request for Additional Information on SER Confirmatory Issue No. 25," J. DeVincentis to V. S. Noonan

(f) PSNH Letter (SBN-1073), dated May 28, 1986, "Response to Request for Additional Information on SER Confirmatory Issue No. 25," J. DeVincentis to V. S. Noonan

# APPENDIX P

# ANALYSIS OF CABLE AND RACEWAY SEPARATION CRITERIA FOR THE SEABROOK NUCLEAR POWER STATION

EGG-NTA-7262

# ANALYSIS OF CABLE AND RACEWAY SEPARATION CRITERIA FOR THE SEABROOK NUCLEAR POWER STATION

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## ABSTRACT

The applicant for the Seabrook Nuclear Power Station has conducted a test program to justify exceptions to the standard criteria for separation of Class 1E electrical cables and raceways. This report provides an evaluation of the test results and an assessment of the acceptability of the reduced separation distances proposed by the applicant.

Docket Numbers 50-443 and 50-444

# FOREWORD

This report is supplied as part of a program for casework review for various nuclear power plants and issues. This work is being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A, by EG&G Idaho, Inc., NRC and I&E Support Branch.

The U.S. Nuclear Regulatory Commission funded this work under the authorization B&R 20-19-40-41-2, FIN No. D6019.

Docket Numbers 50-443 and 50-444

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# ANALYSIS OF
# CABLE AND RACEWAY SEPARATION CRITERIA
# FOR THE
# SEABROOK NUCLEAR POWER STATION

## 1. INTRODUCTION AND SUMMARY

Public Service of New Hampshire, the applicant for the Seabrook Nuclear Power Station, committed to meet the requirements of IEEE Standard 384-1974 as endorsed by Regulatory Guide 1.75, Revision 2, for electrical cable and raceway separation. These documents provide two options for establishing plant specific separation criteria: (1) use guideline separation criteria given in the documents or (2) provide an analysis based on a test program to justify less separation than specified by the guideline criteria. The Seabrook Final Safety Analysis Report (FSAR), Appendix 8A, presently indicates that Seabrook utilized the guideline separation criteria. Problems developed during plant construction which caused the applicant to propose a revised separation criteria with values less than the guideline criteria.

The applicant requested approval of the revised separation criteria in a submittal dated March 31, 1986[1]. The results of a test program and other associated information supporting the revised criteria was included with the submittal. The test program was conducted for the applicant by Wyle Laboratories and reported in Wyle Test Report 47966-02[2]. Additional information and test results were submitted on June 13, 1986.[3]

The INEL staff evaluated the results of the test program and assessed the acceptability of the revised separation distances. The results of the INEL evaluation and assessment are presented in this report.

## 2. DEVIATIONS FROM REGULATORY GUIDE 1.75 SEPARATION CRITERIA

There are four areas of concern in which the applicant proposes to utilize less separation distance between electrical circuits than prescribed by the regulatory guide criteria. These are:

(1) In the Main Control Board (MCB), the regulatory guide criteria require a minimum of six inches of air separation or the installation of barriers between redundant Class 1E circuits. The applicant has not been able to meet this requirement because of the confined area of the MCB. The applicant proposes to accept a lesser spacing of 1-inch free air space or contact with opposite sides of a barrier.

(2) The minimum regulatory guide separation between conduits serving different Class 1E power trains is 1-inch. There was an attempt to maintain this spacing at the Seabrook plant, but deviations have been identified. The applicant proposes to accept a minimum spacing of 1/4-inch where the 1 inch separation is not possible.

(3) The minimum regulatory guide separation between conduits and enclosed cable trays serving different Class 1E power trains is 1-inch. For non-enclosed cable trays, it is 1-foot horizontal or 3-feet vertical. The applicant proposes to accept a minimum of 1/2-inch separation between conduits and non-enclosed cable trays.

(4) The use of aluminum sheath cables (ALS) for lighting circuits is not addressed by the regulatory guide. The lighting system served by the cables is non-safety related. However, as stated in the Seabrook FSAR, Section 8.3, the applicant has elected to associate all of the non-Class 1E circuits with the Class 1E circuits. Associated circuits are defined and permitted by Section 4.5 of the IEEE Standard 384-1974, and by this course of action the plant has been designed with one less separation group

than otherwise would have been required. The applicant proposes to accept 1/4-inch separation between ALS cables and safety-grade trays or conduits and direct contact between ALS cables used in lighting circuits.

## 3. CRITERIA FOR ACCEPTANCE OF TEST RESULTS

The primary criterion for acceptance of the applicant's test results is that they demonstrate that the electrical independence of redundant Class 1E cable divisions is not compromised by the reduced separation distances proposed by the applicant.

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## 4. TEST PROGRAM DESCRIPTION

The test program initially included a series of test configurations simulating the four combinations of cables, trays, conduits and raceways for which reduced separation is proposed. Additional testing, reported in Reference 3, supported the initial test program. Fault currents selected for each test were dependent on the test configuration. For the main control board (MCB) test, which contains only control circuits, the largest size wire used in the MCB was selected for the faulted wire (12 AWG). The fault current was increased in a series of steps with sufficient time between steps for the fault wire to come to an equilibrium temperature, open circuit, or short circuit. A second test was conducted in which the fault wire current was maintained constant at the same current that caused open circuit in the first test. A similar test pattern was followed for other test configurations involving control and instrument wiring.

Tests were conducted on power cables ranging in size from 8 AWG to 500 MCM. In these tests, the fault current was selected based on the locked-rotor current of the largest motor that each cable was sized to supply at Seabrook. The locked-rotor current was chosen for this test based on the assumption that any cable fault would be cleared by either the primary or the backup circuit protective devices. This assumption was subsequently tested[3] and it was shown that the smallest fault current available due to a cable fault will be cleared by the backup circuit breaker before any damage occurs to the target cables. The test fault (locked-rotor) current was maintained constant until the fault cable open circuited, short circuited or the temperature of the cable stabilized.

The fault current for the ALS cable was selected at a value slightly below the trip setting of the backup protective device. Selecting this level of fault current effectively assumes that the first two protective devices (unqualified lighting panel circuit breakers) fail to operate. The backup protective device used to select the current level is the qualified motor control center feeder circuit breaker.

In all of the tests, the primary protective device is assumed to fail to limit the fault current. The target cables were energized throughout each test at normal or above normal current levels. The target cables were subjected to visual and physical inspection, resistance (insulation) measurement, and a high voltage check following each test. Thermocouples were mounted at various points on the fault cables, target cables, and raceways and at various heights above the cables. Currents, voltages, and temperatures during the tests were recorded.

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## 5. EVALUATION OF TEST RESULTS

### 5.1 Internal Panel Separation Criteria

Tests were conducted by the applicant to justify reducing the wire separation criteria in the Main Control Board (MCB) to 1-inch free air or in contact with opposite sides of a barrier for different divisions of redundant circuits. The guideline criteria require 6-inch free air spacing or separation by barriers.

The test setup utilized a 36-inch x 36-inch x 8-inch NEMA 12 enclosure to simulate the environment of the Seabrook MCB. Two tests were conducted between a faulted 1/C 12 AWG SIS wire and a target cable consisting of a 1/C 20 AWG SIS wire, a 1/C 16 AWG teflon wire and a 1/C 24 AWG wire selected from a 30 conductor cable used in the Seabrook MCB. These specimens were separated by 1-inch vertically in free air and by zero inches across an 18 gauge steel barrier. The first test involved a series of step increases in fault cable current until an open circuit occurred at 130 amperes after 3.3 minutes. The second test utilized an initial 130 amperes fault current held constant until an open circuit occurred after about 50 minutes. The cables used in the test are typical of those used in the Seabrook MCB. The specimens used in the test were supplied to the Wyle Laboratories by the applicant. There was no ignition of the faulted cable during either test, nor was there visual evidence of damage to any of the target cable wires. The target cable wires maintained their electrical integrity as evidenced by a post-test insulation resistance and high-voltage test measurements. The maximum target cable temperature measured by thermocouple was at the metal barrier (328°F). The maximum fault cable temperature measured during the second test was 1735°F.

#### 5.1.1 Conclusion

We find that the test results reasonably demonstrate that the reduced separation criteria proposed for the Seabrook MCB does not compromise the independence of redundant Class 1E cable divisions and, therefore, meets the requirements of IEEE Standard 384-1974, as endorsed by Regulatory Guide 1.75, Revision 2.

### 5.2 Conduit to Conduit Separation Criteria

Three tests were conducted to evaluate the proposed conduit to conduit separation of 1/4-inch. One of these tests involved a 3/C #2 AWG fault cable installed in a flexible conduit with a rigid and a flexible conduit containing target cables that were carrying current, mounted 1/4-inch vertically above and parallel with the conduit containing the fault cable. The fault current was applied to the fault cable until it open circuited at 27.3 minutes. The fault cable did not ignite, and the target cables were undamaged with a maximum measured temperature of 142°F.

Another test was conducted utilizing a 500 MCM triplex fault cable. Target cables, carrying current, were in flexible and rigid conduits, 1/4-inch above the fault cable conduit, but at a crossing angle of about 45°. The fault cable in this test did not open circuit, however, it did ignite. The test was terminated after 91.5 minutes, but no damage was done to the target cables. The maximum target cable temperature reached 272°F.

The third test utilized a 500 MCM triplex fault cable in a rigid conduit with target cables, carrying current, in flexible and rigid conduits, parallel to and 1/4-inch above the fault conduit. The fault current was applied to the fault cable until it open circuited in 25.2 minutes. The fault cable did ignite and caused damage to the target cables. The test setup had the end of the target conduits directly above the end of the test conduit. Flame from the test conduit melted the target cable insulation such that the weight of the unsupported cable drew the conductor into the end of the conduit resulting in a short circuit. This situation is not typical of conduit installation at the Seabrook Station. The applicant states that a conduit from one division does not end 1/4 inch above the end of a conduit from another division, and that they do not end in close proximity to each other. The cable inside the conduit was shown not to have had any damage. The end of the flexible conduit also showed melting of the casing material. This was also due to the 1/4 inch spacing between the end of the target and the test conduits. Flame from the end of the test conduit caused the melting of and the ignition of the coating of the flexible conduit. This, also, is not representative of the field installation, where redundant division conduits do not terminate in close proximity to each other.

The applicant states that the test involving the 500 MCM fault cable is overly conservative. A discussion was provided to justify excluding the test information after 5.8 minutes. At this point in the test the fault cable had not yet ignited and the target cable temperature was only 135°F. The justification is based on an analysis of the type of wiring used to connect the motor load to the cables. It was observed that the motor pigtails are several sizes smaller (2 AWG) than the fault cable. The applicant concludes that the pigtails would fail sooner than the supply cable, effectively serving as a slow-acting fuse. Analysis was presented that indicates that pigtail melting would occur in 5.8 minutes for the same locked-rotor current level as was used in the test.

The applicant has provided additional analysis to show that this assumption is correct. In support of the use of the locked-rotor current in the test, 3904 amperes was determined to be the minimum current available due to a phase-to-phase cable fault (a 3 phase fault produces a minimum of 4487 A), neglecting any possibility of the motor pigtails melting. The backup circuit protective device with the largest clearing time is set at 2400 A. This device will trip to clear this fault in between 105 and 225 seconds, assuming the failure of the primary circuit protective device. Larger faults will be cleared in a shorter time. Thus, it can be seen that the use of the locked-rotor current in the tests is a valid assumption for long term overcurrent levels, as the backup circuit protective device will clear any faults associated with the cable itself, and the motor leadin pigtails will melt to clear any motor associated fault. The test, using the assumption, would be over in 5.8 seconds, before any damage to the target cables could occur.

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The applicant has a surveillance test program of insulation resistance (megger) testing. The frequency of this testing for safety-and non-safety-rated cables is specified in Reference 3.

### 5.2.1 Conclusion

Based on the test information and the analysis provided by the applicant, we conclude that the tests demonstrate that 1/4-inch spacing between power conduits does not compromise the independence of redundant Class 1E cable divisions.

## 5.3 Cable Tray-to-Conduit Separation Criteria

Three tests were conducted to evaluate conduit-to-cable tray separation of 1/2-inch. One of these tests involved a 3/C #2 AWG fault cable. The other two tests utilized 500 MCM triplex fault cables. The first test utilized 1/4-inch spacing for the fault cable in a filled cable tray to target cables in a rigid conduit and a wireway mounted above and running parallel with the fault cable tray. The target cables were carrying current. The test results were satisfactory, with short circuit occurring at 20.9 minutes. A short-circuit current was then applied, and the cable open circuited in 2 seconds. The target cables were undamaged.

Except for the 500 MCM triplex fault cable, the second test setup was the same as the first. The cable open-circuited in 61 minutes. The fault cable did ignite and the target cables were damaged. The applicant used the same analysis as in the conduit-to-conduit testing to justify terminating the test information early at 8.4 minutes when the maximum target cable temperature was 105°F.

The third test utilized the 500 MCM triplex fault cable in a rigid conduit 1/2-inch below and parallel with the target cable tray. The fault cable temperature stabilized at 91.5 minutes, at which time the test was terminated. The fault cable did not open circuit, but did ignite. The target cables were not damaged; however, the peak temperature did rise to 414°F. The applicant indicated that early termination of this test at 8.4 minutes would have been justified for the same reasons given for the previous test. The applicant proposes to accept 1/2-inch spacing for cable tray-to-conduit separation even though two of the three tests were conducted with 1/4-inch spacing.

The 1/2 inch spacing was further verified by application of the minimum available cable fault current (3904A phase to phase) to a 500 MCM cable in a tray. This simulated the failure of the primary circuit protective device. The fault current held for 94.3 seconds when the cable conductors shorted together, resulting in increased current (the test set limitation was 7830 A). At 147.6 seconds, the fault cable ignited (it burned for 9 minutes), and at 167.4, the fault cable open circuited, terminating the test.

The target cables, which had been carrying current, remained undamaged, even though the cable inside the conduit reached a peak temperature of 488.4°F, remaining above 480°F for 1 minute and 20 seconds. Insulation resistance and hi-potential tests (2200V AC for 1 minute (1600V AC for instrumentation cable) and physical examination showed no physical or electrical degradation of the target cables. This supports the applicant's assumption and allows the use of the locked-rotor current for the previous testing.

The applicant has a surveillance test program of insulation resistance (megger) testing. The frequency of this testing for safety-and non-safety-rated loads is specified in Reference 3.

Should a cable tray fire occur, procedures for reporting and evaluating the event are in place to initiate remedial action. It would be considered an operational event and would be reported in a station information report. It would be reported to the NRC as part of the Seabrook Station Emergency Plan.

### 5.3.1 Conclusion

Based on the information provided by the applicant, we conclude that the tests have demonstrated that 1/2-inch spacing between uncovered power cable tray siderails and conduits is sufficient to avoid compromising the independence of Class 1E cable divisions.

## 5.4 Separation Criteria for Aluminum Sheath Cables (ALS)

One test was conducted to evaluate the acceptability of 1/4-inch separation between ALS cables and cable trays or conduits. Another test was conducted to evaluate the acceptability of direct contact between ALS cables. As mentioned earlier, the ALS cables supply power to a non-safety-related lighting system. However, the applicant has elected to designate these cables as "associated circuits" as defined by the IEEE Standard 384-1974.

The first test involved a 3/C #4 AWG ALS fault cable mounted 1/4-inch below and parallel to a conduit and cable tray containing target cables. The Target cables were operated at rated current. The fault current was held constant at a value just below the trip setting of the second upstream circuit breaker, causing the fault cable to open circuit at 5.3 minutes. The ALS fault cable ignited out both ends and at two points under the conduit and cable tray. The target cables were not damaged and the maximum target cable temperature was $270^{\circ}$F.

The second test involved 3 ALS cables mounted one above the other and in physical contact. The middle cable was designated the fault cable; the top and bottom cables were target cables and were operated at rated current. The fault cable open circuited in 2.6 minutes. The fault cable did ignite, but did not damage the target cables. The maximum target cable temperature which occurred on the top cable was $526^{\circ}$F. The melting temperature of the aluminum sheath is $1220^{\circ}$F.

### 5.4.1 Conclusion

We find that the test results reasonably demonstrate that the separation criteria proposed for the associated ALS lighting cables do not compromise the independence of redundant Class 1E cable divisions. Therefore, the criteria meet the requirements of IEEE Standard 384-1974 as endorsed by Regulatory Guide 1.75, Revision 2.

## 6. GENERAL CONCLUSIONS

1. Main Control Board - We find the applicant's proposal for minimum spacing of 1-inch free air or contact on opposite sides of a barrier between different divisions of Class 1E redundant control and instrument circuits acceptable.

2. Conduit-to-Conduit - We find the applicant's proposal of 1/4-inch minimum spacing between different divisions of Class 1E redundant circuits enclosed in conduits acceptable.

3. Conduit-to-cable tray - We find the applicant's proposal for a minimum spacing between different divisions of Class 1E redundant circuits where one division is enclosed in conduit that is 1/2-inch above the siderail of the other division's uncovered cable tray acceptable.

4. ALS lighting cable to cable tray or conduit - We find the applicant's proposal for minimum spacing of 1/4-inch between ALS lighting cables and Class 1E circuit divisions acceptable.

5. ALS lighting cable to ALS lighting cable - We find that the applicant's proposal to permit direct contact between ALS associated lighting cables acceptable.

## 7. REFERENCES

1. Public Service of New Hampshire letter, J. DeVincentis to V. S. Noonan, NRC, "Electrical Separation Criteria," March 31, 1986, SBN-979, T.F. B7.1.3.

2. Wyle Laboratories Test Report, "Test Report on Electrical Separation Verification Testing for the Public Service of New Hampshire for Use in the Seabrook Nuclear Power Plant," Test Report No. 47966-02, January 24, 1986.

3. Public Service of New Hampshire letter, J. DeVincentis to V. S. Noonan, NRC, "Electrical Separation Criteria, Additional Information," June 13, 1986, SBN-1107, T.F. B7.1.2.

# APPENDIX Q

# SEABROOK STATION
UNIT 1
DOCKET NUMBER 50-443
DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

EGG-NTA-7287

# SEABROOK STATION
# UNIT 1
# DOCKET NUMBER 50-443
# DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

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# ABSTRACT

The containment purge and vent valve qualification program for the Seabrook Station has been reviewed by the NRR and I&E Support Branch of EG&G Idaho, Inc. The review indicates that the licensee has demonstrated the ability of the 8-inch Posi-Seal butterfly valves COP-VI, -V2, -V3, and -V4 to close against the buildup of containment pressure in the event of a LOCA/DBA.

# FOREWORD

This report is supplied as part of the "Equipment Qualification Case Reviews" project that is being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A, Engineering Branch by EG&G Idaho, Inc., NRR Technical Assistance Division, NRR and I&E Support Branch.

The U.S. Nuclear Regulatory Commission funded this work under the authorization, B&R 20-19-40-41-2, FIN Number A6415.

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## SUMMARY

The Seabrook containment purge and vent valve qualification program has been reviewed by the NRR and I&E Support Branch of EG&G Idaho, Inc., who provide technical assistance to the NRR Division of PWR Licensing-A, Engineering Branch. Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design basis accident, is necessary to assure containment isolation. This demonstration of operability is required by Standard Review Plan (SRP) 6.2.4, Branch Technical Position (BTP) CSB 6-4, and SRP 3.10 for containment purge and vent valves which are not sealed closed during operational conditions 1, 2, 3 and 4.

Information contained in the Seabrook Final Safety Analysis Report (FSAR), purge valve flow test report, stress analyses, and supplemental material formed the basis for this evaluation. Operability of the COP-V1, -V2, -V3, and -V4 valves was based upon the aerodynamic flow tests which simulated the as-built configuration and worst case load combinations. Stress analyses were performed to consider the effects of a combined LOCA and seismic event. In summary, we find that the information submitted has demonstrated the ability of the 8-inch Posi-Seal butterfly valves to close against the buildup of containment pressure in the event of a LOCA/DBA.

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# SEABROOK STATION
# UNIT 1
# DOCKET NUMBER 50-443
# DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

## I. REQUIREMENT

Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design basis accident, is necessary to assure containment isolation. This demonstration of operability is required by Standard Review Plan (SRP) 6.2.4, Branch Technical Position (BTP) CSB 6-4, and SRP 3.10 for containment purge and vent valves which are not sealed closed during operational conditions 1, 2, 3, and 4 (power operation, startup, hot standby, and hot shutdown, respectively).

## 2. DESCRIPTION OF CONTAINMENT ON-LINE PURGE VALVES

The following valves are identified in the licensee submittals and FSAR Table 6.2-83 as being part of the containment on-line purge subsystem.

| Valve Tag No. | Size (inch) | Use | Location |
|---|---|---|---|
| COP-V1 | 8 | Containment On-Line Purge Supply | Outboard containment |
| COP-V2 | 8 | Containment On-Line Purge Supply | Inboard containment |
| COP-V3 | 8 | Containment On-Line Purge Exhaust | Inboard containment |
| COP-V4 | 8 | Containment On-Line Purge Exhaust | Outboard containment |

The 8-inch butterfly valves are manufactured by Posi-Seal (Model 28988, Class 150) and driven by a Matryx air actuator (Model 26062-SR60). The four on-line purge valves are maintained open during normal plant operating conditions 1, 2, 3, and 4 (power operation, startup, hot standby, and hot shutdown, respectively).

The containment pre-entry and refueling purge isolation valves (CAP-V1, -V2, -V3, and -V4) are normally closed during operating conditions 1, 2, 3, and 4 and are opened only during refueling. Consequently, they are not included in the scope of this review.

## 3. DEMONSTRATION OF OPERABILITY

The following documents were submitted for review by the Public Service of New Hampshire, New Hampshire Yankee Division to demonstrate dependability of containment isolation regarding operability of the Seabrook containment on-line purge valves.

1. J. deVincentis, Director, Engineering and Licensing, Public Service of New Hampshire, New Hampshire Yankee Division letter to G. W. Knighton, Chief, Licensing Branch 3, Division of Licensing, U.S. Nuclear Regulatory Commission, Seabrook Station Units 1 and 2, Response to RAI 271.12; Containment Purge and Vent Valve Operability, SBN-889, NRC Accession No. 8511110156, November 6, 1985.

2. Operability Demonstration of the PSI COP Valves for Public Service Company of New Hampshire, et al, performed by Stearns - Roger Manufacturers, Inc., Job No. 62483, United Engineers and Constructors, Inc. (UE&C) Foreign Print No. FP-97786-01, January 22, 1985.

3. Nuclear Seismic and LOCA Analysis, performed by Posi-Seal International, Inc. Report No. 28988SL-001, UE&C Foreign Print No. 93610-03, August 22, 1985.

4. COP Valve Test-Response to RAI, submitted by Public Service of New Hampshire, New Hampshire Yankee Division, April 8, 1986.

5. Request for Additional Information; COP System Isolation Valves, submittal by Public Service of New Hampshire, New Hampshire Yankee Division, SBN-1049, May 13, 1986.

6. Request for Additional Information; COP System Isolation Valves-Further Clarifications, submitted by Public Service of New Hampshire, New Hampshire Yankee Division, June 5, 1986.

The operability demonstration, presented by the licensee in References 1 through 6, is based upon the following considerations.

1. Aerodynamic flow tests were performed which simulated the as-built configuration, using identical valves and operators. Instrumentation measured the valve position, pressure upstream and downstream, maximum shaft torque, closing time, and air stream temperature.

2. The worst case configuration occurs if the inboard containment valve (COP-V3) on the purge exhaust line is stuck open, requiring the outboard valve (COP-V4) to close against the full containment pressure. The worst case was determined by closing the valves individually and simultaneously with the discs mounted in the preferred and reverse flow directions.

3. The increased pressure inside containment during a LOCA will not affect operation of the COP valves. The valve operators are equipped with quick exhaust ports, which permit fast opening by exhausting the cylinder directly to atmosphere.

4. The Posi-Seal valve analysis is based on seismic loads (3 g per axis, all axes acting simultaneously) plus the maximum aerodynamic loads measured from the Stearns-Rogers flow tests, which simulated the containment LOCA pressure. The resulting combined stress is compared with ASME code criteria. The valve operator was evaluated by comparing the manufacturer's torque rating (3260 in-lb) versus the maximum torque measured from the flow tests (2676 in-lb).

5. The on-line purge valves are driven by air operators. Accumulators, handwheels, and torque limiting devices are not used.

6. The valve seat material (Tefzel) is resistant to containment spray chemicals and radiation. The 1-year accident dose rate is

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calculated to be approximately 1.2 x $10^6$ rads compared to the material resistance level of $10^8$ rads. Screens have been included in the elbows upstream of the valves to stop debris from entering the valve seating area. Periodic cleaning of the lines will also reduce the buildup of dust and dirt.

Based upon the assumptions listed above, the highest measured shaft torque from the flow tests was 2676 in-lb at a disc angle of 82° (83.5° corresponds to the fully closed position). The Matryx air operator is rated for 3260 in-lb, which exceeds the torque required to open or close the valve. The results of an analysis of the operator provided in the Posi-Seal report, Reference 3, conclude that the operator is structurally capable of withstanding the combined LOCA and seismic loads.

Using the maximum measured shaft torque values, the critical parts of the valve assembly were analyzed for stress. Seismic accelerations of 3 g were applied simultaneously in all three orthogonal directions. The results of the valve analyses are tabulated in the Posi-seal report, Reference 3. The analyses show that the calculated stress levels are below the ASME Code acceptance criteria.

The aerodynamic flow tests and valve analyses, plus the additional clarification provided in the FSAR and References 1, 4, 5, and 6, are used to support the licensee's conclusions. The licensee has determined that the operability criteria of SRP 6.2.4, BTP CSB 6-4, and SRP 3.10 are satisfied for the containment on-line purge valves COP-V1, -V2, -V3 and V-V4.

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## 4. EVALUATION

We find that the information submitted by the licensee has demonstrated the ability of the 8-inch containment valves COP-V1, -V2, -V3, and -V4 to close against the buildup of containment pressure due to a LOCA/DBA. The following considerations form the basis for our findings.

1. A review of the Seabrook FSAR Sections 6.2.1.1 and 6.2.4 shows that the maximum containment pressure is 46.1 psig, resulting from the combined effects of a full double-ended guillotine rupture of the primary coolant system pipe at the pump suction (DEPS), one of two containment spray pumps failed at the time of containment spray actuation, a nominal initial containment pressure of .5 psig, and a design flow rate of 3010 gpm for the containment building spray system. The licensee's valve qualification tests and analyses were based upon the containment pressure curve for DEPS presented in FSAR Figure 3.11 (B)-1. Using the DEPS pressure curve, the licensee selected a containment pressure of 18 psig corresponding to a closure time of 4.6 seconds (1.5 seconds to reach the setpoint for valve closure, .6 seconds delay for signal processing, 2.0 seconds for valve closure, and a .5 second delay for additional conservatism). The valve aerodynamic flow tests were performed at a nominal inlet pressure of 20 psig. The valve analyses were based upon the maximum measured shaft torque from the flow tests combined with the design seismic loads. The resulting stress valves were well below the ASME Code limits.

2. The flow tests were performed under conditions which simulated the as-built configuration of the containment on-line purge supply and exhaust subsytems. The effects of piping elbows and fittings upstream and downstream of the COP valves were included in the tests. The tests were performed at a nominal inlet pressure of 20 psig, which is higher than the 18 psig value obtained from the DEPS accident pressure curve.

3. The methodology presented in the licensee's submittal to determine the torques acting on the valve stem is acceptable. The calculated torques are based on the worst case configuration of the valves. The analyses calculated closing times for flow in the preferred and non-preferred directions. In addition the effect of back pressure on the actuator was addressed by comparing closure times with the containment pressurized and not pressurized.

4. The licensee's submittal has considered the critical parts of the 8-inch purge valve as reported in Reference 3. The mounting hardware for the operator has also been considered. The acceptance criteria for the stress analysis are traceable to the ASME Code, Section III and .40 times yield strength for non-code shear. The allowable stresses are not exceeded for the full range of motion of the 8-inch valve. The design of the valve internals contains sufficient margin to ensure against being overstressed by a combined LOCA and seismic event. For example, the disc pin has a calculated stress of 21699 psi compared to an allowable limit of 52500 psi.

5. Valve closure times from .22 to .32 seconds were predicted by the Posi-Seal analysis. These times closely matched the closing times of .36 to .46 seconds measured during the flow tests. By comparison the maximum allowable closing time for these valves is 2.0 seconds per Seabrook design specification 9763-006-248-45. The degree of conservatism which underscore the analyses and tests does support the licensee's conclusion that the on-line purge valves will close before the maximum containment pressure has been reached. The licensee has demonstrated by analysis that the post-accident effects of a hypothetical static pressure (60 psig) and temperature (300°F) will not overstress the valve internals.

6. The COP valves were Type C leak tested in accordance with Test Procedure PT-37.1 between March 15, 1986 and March 28, 1986. The NRC (Region I) inspection report associated with the containment integrated leak rate test is inspection Report No. 50-443/85-15.

7. The applicant has indicated that the combined use of debris screens, stainless steel valve internals, a corrosion resistant material (Tefzel) for the valve seat, periodic inspection and scheduled leak tests will be sufficient to preclude the random presence of debris or damage to the valve seat. However, during the simulated LOCA flow tests leakage was observed in valves COP-V1, -V2, and -V3. The licensee has determined that the probable cause of the leaks was the entrapment of debris on the seal grease, followed by embedment of the debris into the seal material when the valves closed. The licensee adds that the presence or absence of leakage had no impact on the valve closure rate or valve position, and did not enter into the flow test evaluation. However, the above preventive measures indicated by the applicant are beyond the scope of this review. Consequently, our evaluation of the operability of the containment on-line purge valves does not cover the dependability of containment isolation for potentially adverse conditions such as the accumulation of debris, entrapment of foreign objects, or damage to the sealing surfaces.

## 5. CONCLUSIONS

We have completed our review of information concerning the ability of the containment on-line purge valves COP-V1, -V2, -V3, and -V4 to provide containment isolation for the Seabrook Station Unit 1. We find that the information submitted has demonstrated the ability of these valves to close against the buildup of containment pressure in the event of a LOCA/DBA.

## 6. REFERENCES

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2. Operability Demonstration of the PSI COP Valves for Public Service Company of New Hampshire, et al, performed by Stearns - Roger Manufacturers, Inc., Job No. 62483, United Engineers and Constructors, Inc. (UE&C) Foreign Print No. FP-97786-01, January 22, 1985.

3. Nuclear Seismic and LOCA Analysis, performed by Posi-Seal International, Inc. Report No. 28988SL-001, UE&C Foreign Print No. 93610-03, August 22, 1985.

4. COP Valve Test-Response to RAI, submitted by Public Service of New Hampshire, New Hampshire Yankee Division, April 8, 1986.

5. Request for Additional Information; COP System Isolation Valves, submittal by Public Service of New Hampshire, New Hampshire Yankee Division, SBN-1049, May 13, 1986.

6. Request for Additional Information; COP System Isolation Valves-Further Clarifications, submitted by Public Service of New Hampshire, New Hampshire Yankee Division, June 5, 1986.

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13. ABSTRACT (200 words or less)

This report is Supplement No. 5 to the Safety Evaluation Report (NUREG-0896, March 1983) for the application filed by the Public Service Company of New Hampshire, et al., for licenses to operate Seabrook Station, Units 1 and 2 Docket Nos. STN 50-443 and STN 50-444). It has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission and provides recent information on open items identified in the SER. The facility is located in Seabrook, New Hampshire. Subject to favorable resolution of the items discussed in this report, the staff concludes that the facility can be operated by the applicant without endangering the health and safety of the public.

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